OPA
Ontario Power Authority

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VIA COURIER and/or REGISTERED MAIL

October 26, 2007

To: Band office and Chiefs and Tribal Councils of First Nations, the Métis Nation of Ontario, and County, Regional and District Municipal offices in Ontario

Re: Ontario Power Authority
Integrated Power System Plan and Procurement Process
Ontario Energy Board ("OEB") File No. EB-2007-0707

I am writing to inform you that on August 29, 2007 The Ontario Power Authority (the "OPA") filed an application with the Ontario Energy Board under the *Electricity Act, 1998*. The OPA "is seeking an order of the Board approving the Integrated Power System Plan (the "IPSP") and certain procurement processes. The Board has assigned file number EB-2007-0707 to this application. The IPSP is a plan for the management of Ontario's electricity system. It identifies the electricity conservation, generation and transmission investments that the OPA proposes for the adequacy and reliability of electricity supply and demand management in Ontario. The procurement processes are designed to manage electricity supply, capacity and demand in accordance with the IPSP. The IPSP affects the supply of electricity to all Ontario consumers."

On October 22, 2007 the OPA received a Notice of Application ("NOA") from the Ontario Energy Board and is directed to serve you with a copy of the NOA, the evidence, any amendments thereto, including a proposed issues list. The NOA provides you with information on the application and its review, including details on how to participate.

Accordingly, enclosed is the aforementioned information for your review. The Board's purpose in directing the OPA to serving County, Regional and District Municipal offices is also so that it is made available for public review.

In accordance with Conservation measures the OPA is providing the IPSP evidence electronically on the enclosed CD. Additionally you may access all EB-2007-0707 documents which are posted on the OPA's website at www.powerauthority.on.ca. The electronic versions may be copied and are searchable.

Yours truly,

Miriam J. Heinz
Regulatory Coordinator

RECEIVED
NOV 14 2007
R.M.Y. CLERK

Attachments: (OEB NOA; CD of IPSP evidence; proposed issues list)

cc: EB-2006-0233 Interested Parties (by courier)

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Kelly, Denis

From: Miriam Heinz [Miriam.Heinz@powerauthority.on.ca]
Sent: November 13, 2007 3:43 PM
Subject: Urgent confirmation required OPA Integrated Power System Plan Notice of Application
Attachments: OPA Cvr Ltr NOA 071026.pdf; NOA English and French.pdf; Proposed Issues List 2007-10-26.pdf

By cover letter dated October 26, 2007 the OPA sent packages to various municipal offices across Ontario. The packages contained Notice of Application regarding the Ontario Power Authority's ("OPA") Integrated Power System Plan ("IPSP"); a proposed issues list; and a CD containing the IPSP submission and supporting evidence. The OPA is now tracking the packages it sent to ensure they arrived at their destinations. To date we are not able to determine whether the package arrived at your office and are thus re-sending the material through this email as well as by overnight courier.

I am attaching the materials that you should have received and will follow-up with another copy via courier.

The IPSP is available on the OPA website at: OPA - Corporate Information: Integrated Power System Plan

I urge you to read the attached materials and note please that the last day of publication as noted in the Notice of Application is today, November 13th. Therefore, in accordance with the dates set in the Notice of Application you have 14 days to send in your interventions to the Ontario Energy Board or until no later than November 27th. If you wish to send comments to the attached proposed issues list, you have until no later than December 13th.

Please reply at your earliest convenience to confirm receipt of this email.

If you have any further questions, please do not hesitate to call me.

Thank you.

Miriam Heinz
Regulatory Coordinator
Ontario Power Authority
(416) 969-6045

Ontario Energy Board

Commission de l'Énergie de l'Ontario

Ontario

EB-2007-0707

NOTICE OF APPLICATION FOR APPROVAL OF THE INTEGRATED POWER SYSTEM PLAN AND PROCUREMENT PROCESSES

The Ontario Power Authority (the "OPA") has filed an application with the Ontario Energy Board dated August 29, 2007 under the *Electricity Act, 1998*, S.O. 1998, c. 15, Sched. A (the "Act"). The applicant is seeking an order of the Board approving the Integrated Power System Plan (the "IPSP") and certain procurement processes. The Board has assigned file number EB-2007-0707 to this application.

The IPSP is a plan for the management of Ontario's electricity system. It identifies the electricity conservation, generation and transmission investments that the OPA proposes for the adequacy and reliability of electricity supply and demand management in Ontario. The procurement processes are designed to manage electricity supply, capacity and demand in accordance with the IPSP. The IPSP affects the supply of electricity to all Ontario consumers.

In developing the IPSP, the OPA was required to comply with the Act, the government's Supply Mix Directive and the Integrated Power System Plan Regulation. Under section 25.30(4) of the Act, the Board is required to review the IPSP to ensure that it complies with directions issued by the Minister of Energy and that it is economically prudent and cost effective. In addition, under section 25.31(4) of the Act, the Board is required to review the OPA's proposed procurement processes. The Supply Mix Directive, the IPSP Regulation, the Procurement Processes Regulation and relevant sections of the Act are posted on the Board's website under the IPSP link.

In addition to electricity conservation initiatives, the OPA has identified various electricity generation and transmission projects throughout the province that it is recommending be undertaken. These projects may affect your community. Maps and descriptions of the proposed projects are included in the IPSP.

How to see the IPSP

Copies of the IPSP, the procurement processes application and the supporting pre-filed evidence will be available for public inspection:

- on the OPA's website www.powerauthority.on.ca
- on the Board's website www.oeb.gov.on.ca
- at the Board's office;
- at the OPA's head office; and
- at County, Regional and District Municipal offices throughout Ontario.

If you have trouble viewing the application or for information on where to obtain a copy of the IPSP, please call the OPA at 1-800-722-0679.

A Two Phase Review

The Board intends to proceed with this review in two phases.

In phase 1, the Board will develop an issues list. This list will determine which issues will be addressed in the subsequent review of the application. Only those issues on the approved issues list will be considered during the review. The Board instructed the OPA to develop a proposed issues list for the review of the IPSP and the proposed procurement processes, structured by reference to the findings the Board has to make, according to the legislation and Ministerial directions. The Board is seeking your views on what issues should be considered by the Board in its review. The issues list proposed by the OPA is available at the same locations as the IPSP.

This notice is Notice for phase 1 of the proceeding. Phase 2 will be the review of the evidence filed by the OPA and any other parties. The phase 2 notice will be published later, at the start of phase 2, providing details on how to participate in that phase of the proceeding.

How to Participate

You can participate in the development of the issues list in two ways:

1. **Give Comments to the Board**

   If you want to comment on what issues the Board should consider in reviewing the plan and procurement processes, your written comments must be received by the Board no later than **30 days** from the publication date of this notice. Your comments will be provided to the Board and will be part of the public record. A notice for phase 2 of the proceeding, giving you an opportunity to comment on the content of the IPSP and proposed procurement processes, will be published once the issues list has been set.

   The Board accepts written comments by either post or e-mail at the addresses below. Forms for providing comments on the proposed issues list are available on the Board's website or by calling the Board's Consumer Relations Centre at 1-877-632-2727.

2. **Become an Intervenor**

   You may ask to become an intervenor if you wish to actively participate in phase 1 by appearing before the Board to make formal submissions on the issues list. Intervenors have procedural rights and obligations as described in the Board's Rules of Practice and Procedure.

   Please refer to the "How to Become an Intervenor" section of the IPSP page on the Board's website. The Board has strict rules and timelines for interventions and filings. Your letter seeking intervention, compliant with the Board's rules and filing guidelines, must be received by the Board and copied to the OPA no later than **14 days** from the publication date of this notice.

For phase 1, intervenors are invited to make written submissions on the draft issues list proposed by the OPA. Submissions must be filed with the Board and copied to the OPA no later than **30 days** from the publication date of this notice. The Board will issue further procedural documents relating to the development of the issues list, and relating to phase 2, the review of the application and supporting evidence.

How to Contact Us

In responding to this notice please include Board file number EB-2007-0707 in the subject line of your e-mail or at the top of your letter. It is also important that you provide your name, postal address and telephone number and, if available, an e-mail address and fax number. All written communications should be directed to the attention of the Board Secretary at the address below, and be received no later than 4:45 p.m. on the required date.

Need More Information?

Further information on the IPSP may be obtained from the OPA website www.powerauthority.on.ca. Further information on how to participate in the review may be obtained by visiting the Board's Web site at www.oeb.gov.on.ca or by calling our Consumer Relations Centre at 1-877-632-2727.

Addresses

Ontario Energy Board
2300 Yonge St.,
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Toronto, Ontario
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Boardsec@oeb.gov.on.ca

Ontario Power Authority
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Suite 1600,
Toronto, Ontario
M5H 1T1
EB-2007-0707@powerauthority.on.ca

DATED at Toronto, October 22, 2007

ONTARIO ENERGY BOARD

Original signed by

Kirsten Walli
Board Secretary

Issues List Based on OEB Direction to Follow Legal Approval Requirements for IPSP and Procurement Process

The Notice of Application in this Proceeding states that the Ontario Energy Board has "instructed the OPA to develop a proposed issues list for the review of the IPSP and the proposed procurement processes, structured by reference to the findings that the Board has to make, according to the legislation and Ministerial directions."

The following separates the Issues List into two main parts: Part I -- The IPSP; and Part II -- The Procurement Processes.

Part I -- The IPSP

Section 25.30 of the *Electricity Act* addresses the Board's review of the IPSP as follows:

> 25.30 (1) Once during each period prescribed by the regulations, or more frequently if required by the Minister or the Board, the OPA shall develop and submit to the Board an integrated power system plan,
>
> (a) that is designed to assist, through effective management of electricity supply, transmission, capacity and demand, the achievement by the Government of Ontario of,
>
> (i) its goals relating to the adequacy and reliability of electricity supply, including electricity supply from alternative energy sources and renewable energy sources, and
>
> (ii) its goals relating to demand management; and
>
> (b) that encompasses such other related matters as may be prescribed by the regulations.
>
> ...
>
> (4) The Board shall review each integrated power system plan submitted by the OPA to ensure it complies with any directions issued by the Minister and is economically prudent and cost effective.

The legislation therefore requires the Board to review the IPSP for two purposes: (1) compliance with directions issued by the Minister; and (2) economic prudence and cost effectiveness. The OPA detailed analysis on these requirements is set out at Exhibit A-2-2 of the Application. The specific issues list in respect of these requirements is set out below.

Issue (1): Compliance with Directions Issued by the Minister of Energy: Supply Mix Directive, June 13, 2006

1. Does the IPSP 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?
2. Does the IPSP assist the government in meeting its target for 2010 of increasing the installed capacity of new renewable energy sources by 2,700 from the 2003 base, and increase the total capacity of renewable energy sources used in Ontario to 15,700 MW by 2025?
3. Does the IPSP plan for nuclear capacity to meet base-load requirements and limit the installed in-service capacity of nuclear power over the life of the plan to 14,000 MW?
4. Does the IPSP 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. Does the IPSP 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?
6. Does the IPSP plan to 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. Does the IPSP comply with Ontario Regulation 424/04; specifically, in developing the integrated power system plan, has the OPA done the following:
    - Consulted with consumers, distributors, generators, transmitters and other persons who have an interest in the electricity industry in order to ensure that their priorities and views are considered in the development of the plan?
    - Identified and developed innovative strategies to accelerate the implementation of conservation, energy efficiency and demand management measures?
    - Identified opportunities to use natural gas in high efficiency and high value applications in electricity generation?
    - Identified and developed innovative strategies to encourage and facilitate competitive market-based responses and options for meeting overall system needs?

- Identified measures that will reduce reliance on procurement under section 25.32(1) of the Act?
- Identified factors that it must consider in determining that it is advisable to enter into procurement contracts under subsection 25.32 of the Act?
- Ensured that safety, environmental protection and environmental sustainability are considered in developing the plan?
- Ensured that for each electricity project recommended in the plan that meets the criteria set out in subsection 8(2) of Regulation 424/04, the plan contains a sound rationale including:
    - **i.** an analysis of the impact on the environment of the electricity project; and
    - **ii.** an analysis of the impact on the environment of a reasonable range of alternatives to the electricity project?

Issue (2): Economic Prudence and Cost Effectiveness

As is discussed in Exhibits B-1-1 and B-3-1 of the IPSP Application, the OPA's plan to achieve the Supply Mix Directive's goals was developed by identifying the areas of discretion left open by the Supply Mix Directive and applying the OPA's Planning Criteria to make decisions in those areas. This resulted in an IPSP that prioritizes how Conservation and supply resources should be acquired through (i) meeting the requirements of the Supply Mix Directive in light of the OPA's planning criteria (the "Directive Priority"); and (ii) meeting the requirements of the Supply Mix Directive in light of lead times and necessary transmission enhancements (the "Implementation Priority"). The Directive Priority proposes the priority order in which Conservation and supply resources should be treated. The Implementation Priority is the relative chronological ordering of proposed resource additions.

The IPSP is the combination of the Directive Priority and the Implementation Priority.

Table 1 summarizes the decisions made in the IPSP by applying the Directive Priority and the Implementation Priority.

The issue is whether the decisions identified in Table 1 are economically prudent and cost effective.

Table 1					
Subject of Directive	**Directive Goals**	**Directive Priority**	**Implementation Priority**	**Current Mix of Projects/ Facilities/ Programs (Evidence Reference)**	**Procurement Authorization (for resources to be acquired by end of 2010)**
Conservation	2010: 1,350 MW 2025: an additional 3,600 MW	Maximize feasible cost effective contribution from Conservation before supply resources.	2010 goals to be met through resource acquisition; experience with programs to provide information on how to economically meet and exceed 2025 goal using combination of resource acquisition, capability building and market transformation programs.	2010: Exhibit D-4-1, Table 21 2025: Exhibit D-4-1, Table 22	Government Directives
Renewable Supply	10,402 MW by 2010 15,700 MW by 2025	Maximize feasible cost effective contribution from renewable sources before other supply resources in the following order of economic priority: hydro, bioenergy, and wind.	2010: All feasible renewable resources that can be installed prior to 2010 should be acquired; 2025 goal to be met by first applying all feasible hydro resources (2,921 MW); all feasible bioenergy (450 MW); and all small, standard offer wind projects (1,148 MW). The remainder of the goal (1,891 MW) to be made up of large wind projects. The order of implementation will be coordinated with necessary transmission enhancements.	2010: Exhibit D-5-1, Table 1 2025: Exhibit D-5-1, Tables 2, 19, 31, and 33.	Government Directives
Nuclear for Baseload	Up to 14,000 MW	Make up remaining baseload requirements remaining after Conservation and renewable supply with nuclear supply. Refurbished nuclear facilities have planning	10,249 MW of nuclear capability required, either from refurbishments or new build. Depending on refurbishments, new nuclear capacity of 1,400 MW to 3,400 MW, starting in 2018.	Exhibit D-6-1 Table 14	No Procurements Planned

Table 1

Subject of Directive	Directive Goals	Directive Priority	Implementation Priority	Current Mix of Projects/ Facilities/ Programs (Evidence Reference)	Procurement Authorization (for resources to be acquired by end of 2010)
		advantages and are generally preferred to new nuclear facilities. However, each case is fact dependent.			
Replacement for Coal Fired Generation	Replace coal-fired generation in earliest practical timeframe.	Replacing coal-fired generation requires replacing its three types of contributions to Ontario's electricity needs: capacity (6,434 MW), energy production (24.7 TWh) and reliability (flexibility, dispatch ability, and ability to respond to unforeseen supply availability).	15,000 MW of resources are planned by 2015, partly to replace coal, partly to meet growth, and partly to catch up with deficiencies that existed in the beginning of the planning horizon. Gas-fired generation will be installed in the areas of York Region, Kitchener Waterloo and Southwest GTA. This will allow for the energy and capacity production contributions to be replaced by 2012. The reliability contribution will be replaced by these and other facilities by 2014.	Exhibit D-7-1, Table 5	Conservation and Renewable Resources: Government Directives GFG: OEB Approved Procurement Process
Natural Gas	Confine gas to peaking, high value and high efficiency uses.	Gas fired generation will be used to meet peak and intermediate requirements and to provide flexibility. When gas-fired resources are used, they should be restricted as much as possible to either simple cycle gas generation (to meet peaking requirements) or combined cycle	In addition to meeting the local area supply requirements in York Region, Kitchener-Waterloo and Southwest GTA, current facilities that operate as baseload may be converted to meet intermediate and peaking needs and energy will be procured from Lennox GS to replace the Reliability Must Run Contract with the IESO. An additional 400-650 MW of "proxy gas" may be required around	Exhibit D-8-1, Table 9	OEB Approved Procurement Process

Table 1					
Subject of Directive	**Directive Goals**	**Directive Priority**	**Implementation Priority**	**Current Mix of Projects/ Facilities/ Programs (Evidence Reference)**	**Procurement Authorization (for resources to be acquired by end of 2010)**
		gas generation (to meet intermediate requirements). Any new contracts and facilities should reflect these requirements as much as possible.	2017.		

Part II -- The Procurement Process

Section 25.31 of the *Electricity Act* addresses the Board's review of the Procurement Processes as follows:

> 25.31 (1) The OPA shall develop appropriate procurement processes for managing electricity supply, capacity and demand in accordance with its approved integrated power system plans.
>
> ...
>
> (4) The Board shall review the OPA's proposed procurement processes and any proposed amendments and may approve the procurement processes or refer all or part of them back with comments to the OPA for further consideration and resubmission to the Board.

Issues

Are the OPA's proposed procurement processes appropriate to manage electricity supply, capacity and demand in accordance with the IPSP?

ONTARIO ENERGY BOARD

IN THE MATTER OF the sections 25.30 and 25.31 of the Electricity Act, 1998

AND IN THE MATTER OF an Application by the Ontario Power Authority for review and approval of its integrated power system plan and approval of its proposed procurement process.

SUBMISSION FOR APPROVAL

1. The Applicant, the Ontario Power Authority ("OPA"), is a non-share capital corporation established under the *Electricity Act, 1998* (the "Act"). The OPA is the independent electricity system planner for the province of Ontario.

2. The OPA's statutory objects require it to, *inter alia*, ensure adequate, reliable and secure electricity supply and resources in Ontario and to conduct independent planning for electricity generation, demand management, conservation and transmission. More specifically, the Act mandates the OPA to:

   - Once during each period prescribed by regulations, or more frequently if required by the Minister of Energy (the "Minister") or the Ontario Energy Board (the "Board"), develop and submit to the Board for its review and approval an integrated power system plan (the "IPSP") which shall follow any directives issued by the Minister relating to the government's electricity goals; and
   - Develop appropriate procurement processes for managing electricity supply, capacity and demand in accordance with the IPSP and apply to the Board for approval of its proposed procurement processes.

3. On June 13, 2006, the Minister issued a supply mix directive (the "Directive") directing the OPA to create an IPSP to meet specific goals relating to conservation, renewable energy, nuclear energy, natural gas, coal-fired

generation and transmission. The Directive also required the OPA to comply with Ontario Regulation 424/04 (the "IPSP Regulation").

4. The IPSP Regulation requires the OPA to develop and submit an IPSP that covers a period of twenty years from the date of its submission and to develop and submit an updated twenty year plan every three years. The IPSP Regulation also requires the OPA to follow certain requirements in developing the IPSP.

5. In addition to the IPSP Regulation, Ontario Regulation 426/04 (the "Procurement Process Regulation") requires the OPA to comply with certain principles in developing its procurement process.

6. The OPA developed an IPSP which covers a period of twenty years and complies with the goals and requirements set out in the government's Directive and the IPSP Regulation.

7. The OPA also developed a procurement process for managing electricity supply, capacity and demand in accordance with the IPSP. This procurement process complies with the requirements of the Act and the Procurement Process Regulation.

8. Pursuant to section 25.30 and 25.31 of the Act, the OPA hereby seeks the following approvals from the Board:

- Approval of the IPSP as set out and in the form attached as Exhibit B-1-1; and
- Approval of the OPA's proposed procurement process as set out and in the form attached as Exhibit B-2-1.

9. This Application is supported by pre-filed written evidence which addresses the IPSP and procurement process requirements in the Act, the IPSP Regulation and the Procurement Process Regulation. The OPA also used the *Report of the Board on the Review of, and Filing Guidelines Applicable to, the Ontario Power Authority's Integrated Power System Plan and Procurement Processes* (the "IPSP Filing Guidelines") as a guide to preparing its pre-filed evidence. The pre-filed evidence may be amended by the OPA from time to time prior to the Board's final decision. Further, the OPA may seek to meet with Board Staff and intervenors in order to identify and address any issues arising from this Application for the purpose of settling or disposing of such issues.

10. The OPA proposes the following title for this proceeding: *Ontario Power Authority Submission for Approval of its Integrated Power System Plan and Proposed Procurement Process.*

11. The OPA requests that a copy of all documents filed with the Board be served on the OPA and the OPA's counsel, as follows:

(a) The OPA:

Ms. Miriam Heinz
Regulatory Coordinator
Ontario Power Authority

Mailing Address:	120 Adelaide Street West Suite 1600 Toronto, Ontario M5H 1T1
Telephone:	(416) 969-6045
Fax:	(416) 967-9147
Electronic access:	miriam.heinz@powerauthority.on.ca

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(b) The Applicant's counsel:

Mr. George Vegh
McCarthy Tétrault LLP

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and,

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and,

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Mr. Glenn Zacher
Stikeman Elliott LLP

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DATED at Toronto, Ontario, this 29th day of August, 2007.

By its Counsel in this Proceeding

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THE INTEGRATED POWER SYSTEM PLAN FOR THE PERIOD 2008-2027

1.0 INTRODUCTION

This exhibit presents the Integrated Power System Plan (the "IPSP" or the "Plan") for the period 2008 to 2027.

2.0 OVERVIEW

The IPSP is designed to assist, through the effective management of electricity supply, transmission, capacity and demand, the achievement of the government of Ontario's goals identified in the Supply Mix Directive dated June 13, 2006 (the "Directive").

As discussed in Exhibit B-3-1, the OPA's plan to achieve the Directive's goals was developed by identifying the areas of discretion left open by the Directive and applying the OPA's planning criteria to make decisions in those areas. This resulted in an IPSP that prioritizes how Conservation and supply resources should be acquired through (i) meeting the requirements of the Directive in light of the OPA's planning criteria (the "Directive Priority"); and (ii) sequencing the installation of resources, in light of lead times and necessary transmission enhancements (the "Implementation Priority").

2.1 Directive Priority

With respect to the Directive Priority, the Directive identifies a number of goals respecting Conservation and supply resources. The IPSP ensures that these goals are met by identifying the priority order in which the resources are planned to meet the province's resource requirements with respect to capacity, electricity production, and flexibility. The IPSP is not represented by any single case or scenario but rather, it represents the ongoing capability to meet resource requirements across a range of conditions. The range of conditions described in Exhibits D-9-1 and G-1-1 illustrates the possible range of resource requirements. In planning to meet an estimated range of resource requirements, the IPSP identifies specific priorities for the near-term, but will, more generally, develop options for the mid term and explore opportunities for the longer term.

The resources identified in the Directive each make their own contribution to meeting these requirements. In summary, the Directive Priority is as follows:

1. Maximize feasible cost effective contribution from energy efficiency, demand management, fuel switching, and customer based generation ("Conservation");
2. Maximize feasible cost effective contribution from renewable sources;
3. Make up baseload requirements remaining after Steps 1 and 2 above with nuclear power;
4. Replace coal-fired generation with power from committed and planned resources. Specifically, in order to ensure that existing coal-fired facilities are replaced by 2014, gas-fired generation ("GFG") facilities are planned to be installed in the areas of Northern York Region, Kitchener-Waterloo-Cambridge-Guelph and the Greater Toronto Area ("GTA") by 2014; and
5. Restrict contribution of GFG to specific projects as required when additional Conservation and renewable resources are not feasible or cost effective.

Transmission is a facilitator and enabler of supply choices and therefore transmission considerations were integrated in all steps in the planning process. Transmission planning is particularly important in meeting the Directive's renewable goals since the accessing and delivery of potential renewable resources depends on making substantial transmission enhancements.

2.2 Implementation Priority

The Directive Priority outlined above does not necessarily represent the order in which resources will be installed. For example, in light of necessary transmission investments to enable hydroelectric resources, many hydroelectric resources will be brought on later in the Plan term. As a result, the Directive Priority is accompanied by an Implementation Priority.

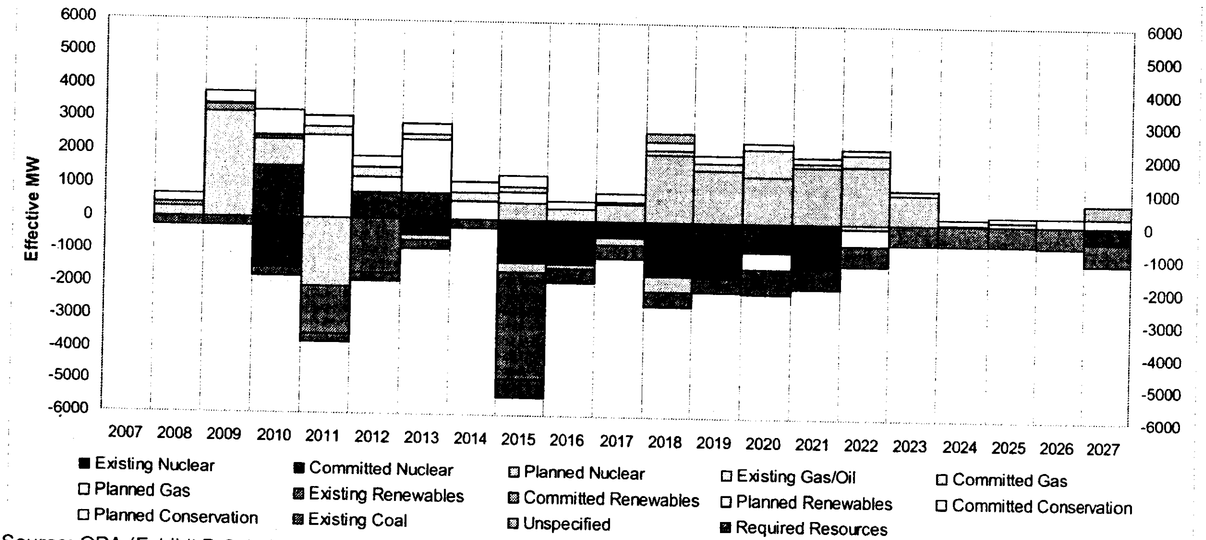
The Implementation Priority should also be understood as enabling contributions from different resources as opposed to a rigid in-service schedule for specific facilities. The IPSP ensures that resources will be prioritized in an economically prudent and cost effective manner by creating opportunities for resource acquisition in the future. In other words, it is economically prudent and cost effective to have more than one choice when it comes to acquiring a resource.

It is also important to note that the IPSP will be implemented through a number of projects, facilities and programs, some of which are within the OPA's control and some of which are not. There are a number of initiatives that the OPA is currently pursuing and plans to pursue in order to implement the IPSP in accordance with the Directive and Implementation Priorities. These initiatives are summarized at the end of this exhibit at Table 5. The specific projects, facilities, and programs that are referenced in Table 5 comprise the OPA's current view of a reasonable way to implement the IPSP. The sequence and specific projects will likely change as opportunities present themselves in the market place. Included within those projects are resources that the OPA intends to procure through the OEB-approved procurement process prior to the end of 2010. These procurements are addressed in greater detail in Exhibit D-10-1. Also included in Table 5 are resources and programs that the OPA intends to pursue under existing Directives issued by the Minister of Energy under the *Electricity Act, 1998* (the "Act").

The change in the installed capacity of resources resulting from the Directive and Implementation Priorities is illustrated in summary form in Figure 1 below[1].

[1] This exhibit, including Figure 1, presents Case 1A. Case 1 B (which has minor variations in respect of this Figure), is presented in Exhibit D-9-1, Figure 12 and is described throughout the remainder of the evidence.

Figure 1: Annual Resource Additions and Reductions (Effective MW)



Source: OPA (Exhibit D-9-1, Figure 5)

The remainder of this exhibit addresses how the IPSP prioritizes and implements the contribution from the Conservation and supply resources identified in the Directive.

3.0 CONSERVATION

3.1 The Directive

The Directive's Conservation goals are to reduce demand by 1,350 MW by 2010 and an additional 3,600 MW by 2025. The Directive states:

> 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 reductions 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.

Directive Priority

Conservation takes priority over supply resources in that the IPSP first applies all economic and feasible Conservation to meeting resource requirements before applying supply resources. Economic Conservation is defined as Conservation that is more cost effective than supply resources as determined by applying a Total Resource Cost ("TRC") Test. Feasible Conservation is Conservation that can be used for resource planning. In other words, the Conservation contribution can make as predictable and reliable a contribution to meeting resource requirements as the alternative supply resource.

The OPA will seek to develop and identify Conservation opportunities that exceed the Directive's 2010 and 2025 Conservation goals. However, determining whether and how this can be done requires a realistic understanding of the feasibility of achieving Conservation beyond the goals. Such an understanding can only occur as Ontario gains more experience in Conservation and in associated evaluation, measurement and verification ("EM&V") results. In addition, the OPA will monitor future policy changes such as codes and standards, price, carbon taxes and land use that underpin the potential estimate to establish the feasibility of exceeding the goal.

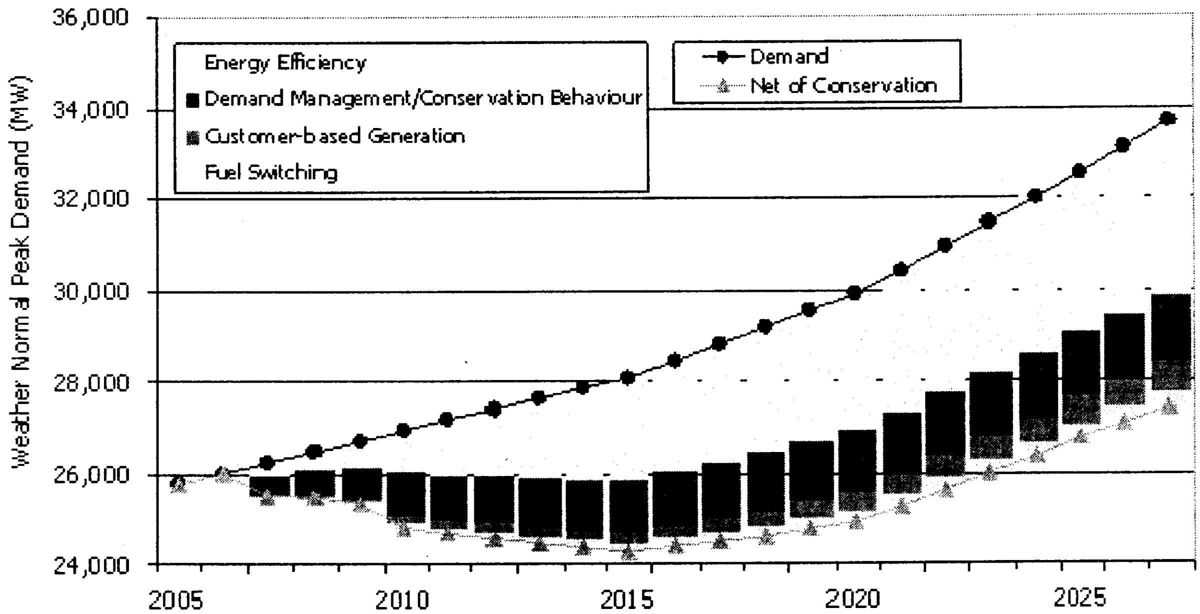
The IPSP has sufficient flexibility to develop a number of options on both the Conservation and the supply side. If experience from the 2008 to 2010 Conservation programs demonstrates that there is feasible Conservation to exceed the Directive goal, that Conservation will be compared to alternative supply resources before any commitment is made.

Implementation Priority

There are four types of Conservation identified in the Directive: efficiency, demand reduction/conservation behaviour, self-generation and fuel switching.

The contribution of each of the Conservation categories over the term of the IPSP are illustrated in Figure 3, as follows:

Figure 3: Impact of Conservation on Peak Demand (MW)



Source: OPA (Exhibit D-4-1, Figure 1)

The programs through which the OPA currently intends to implement the 2010 Conservation goals are set out in Table 1, below:

Table 1: Committed Conservation Resources 2008 – 2010

	PROGRAM TARGETS			CONSERVATION CATEGORIES			
Program	**Target (MW)**	**Free Rider Rate (%)**	**Net Demand Reduction (MW)**	**Energy Efficiency (MW)**	**Demand Management (MW)**	**Fuel Switching (MW)**	**Customer-based Generation (MW)**
New Construction Program	45	30	32	32			
Existing Buildings Retrofit	242	30	169	169			
Low Income & Aboriginal	16	30	11	11			
Demand Response	105	30	74		74		
Total Mass Market Programs	**408**	**30**	**286**	**212**	**74**		
New Construction Program	55	30	39	39			
Existing Building Retrofit	492	30	344	274		70	
Socially Assisted Housing	29	30	20	20			
Total Commercial/Institution Market Programs	**576**	**30**	**403**	**333**		**70**	
Industrial Markets							
Industrial Programs	113	30	79	79			
Demand Response Programs	451	30	316		316		
Total Industrial Market Programs	**564**	**30**	**395**	**79**	**316**		
Customer-based Generation							
Customer-based Generation Programs	211	30	**148**				148
Total OPA Resource Acquisition Programs	**1,759**	**30**	**1,231**	**625**	**390**	**70**	**148**
Other Influenced CDM							
Smart Meters	**176**	**0**	**176**				
Total Conservation & Demand Management[2]	**1,940**		**1,410**	**620**	**390**	**70**	**150**

Source: OPA (Exhibit D-4-1, Table 20)

All of the programs to meet the 2010 goals will be carried out in accordance with directives issued by the Minister of Energy. As a result, they will not be carried out in accordance with the procurement process for which the OPA is seeking OEB approval. The mix of programs will likely change as better opportunities present themselves.

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[2] Totals have been rounded to nearest 10 MW.

4.0 RENEWABLE SUPPLY

4.1 The Directive

The Directive's goal is for a 2010 target for renewable supply of 10,402 MW and a goal of approximately 15,700 MW for 2025. It states:

> Increase Ontario's use of renewable energy such as hydroelectric, wind, solar and biomass for electrical generation. The plan should assist the government in meeting its target for 2010 of increasing the installed capacity of new renewable energy resources 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.

Directive Priority

Renewable supply is second in priority to Conservation. After accounting for the feasible and economic contribution of Conservation, the IPSP applies the feasible and economic contribution from renewable supply. The OPA's approach to determine the feasible and economic contribution of renewable supply is as follows:

- All feasible hydroelectric resources are included on the basis that hydroelectricity is the most economic of the renewable resources;
- Bioenergy, wind (small sites) and solar resources were included generally on the basis of the expected response to standard offer procurement programs; and
- Large wind sites were used to provide the remaining resources needed to meet the goal. The sites were included on the basis of lowest "all-inclusive unit cost" (in which the cost of associated transmission is included).

The total capacity of the assumed planned resources meets the Directive's renewable goals. Unlike the plan for Conservation goals, the IPSP does not seek to exceed the Directive's goals for renewable resources. This is because the incremental renewable resource would be large wind projects. These projects would not be cost effective when compared to the supply resources included in the Plan that would be displaced.

Implementation Priority

There are two key elements to implementing the renewable goals: the acquisition of renewable supply and the transmission enhancements that are necessary to facilitate the supply.

With respect to supply, the 2010 Directive goal of 10,402 MW of renewable resources will be implemented through acquiring all renewable resources that may be feasibly implemented by that time.

The mix of renewable resources that currently make up the most attractive opportunities is illustrated in Table 2:

Table 2: Meeting the 2010 Renewable Resources Goal (Installed Capacity in MW)

		MW
The 2003 Base		7,702
Hydroelectric	7,636	
Bioenergy	66	
Resources Added Since 2003		
Hydroelectric	152	
Wind	395	
Bioenergy	9	
Total Resources Added Since 2003		**556**
Existing Resources		8,258
Hydroelectric	7,788	
Wind	395	
Bioenergy	75	
Committed Resources		
RES Hydroelectric	43	
RES Wind	865	
SOP Solar	88	
SOP Hydroelectric	19	
SOP Wind	385	
SOP Bioenergy	14	
Total Committed Resources		**1,415**
Quebec Interconnection		**1,250**
Planned Resources		
Hydroelectric	97	
Total Planned Resources		**97**
TOTAL RESOURCE INCREASE		**3,318**
REQUIRED RESOURCE INCREASE		**2,700**

Source: OPA (Exhibit D-5-1, Table 1)

The 2025 Directive goal of 15,700 MW of renewable resources will be implemented in order of feasibility in light of transmission availability. The mix of renewable resources that currently make up the most attractive opportunities is set out in Table 3:

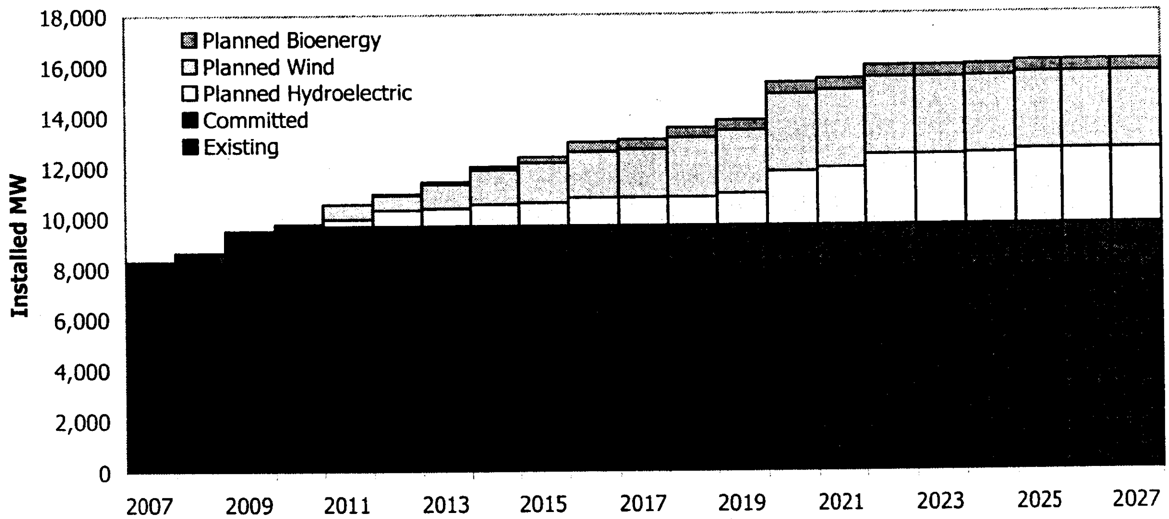
Table 3: Meeting the 2025 Renewable Resources Goal – Existing, Committed and Planned Resources (Resources Used in Ontario - Installed MW)

	MW
Hydroelectric	**10,771**
Existing	7,788
Committed	62
Planned	2,921
Wind Power	**4,685**
Existing	395
Committed	1,251
Planned	3,039
Bioenergy	**539**
Existing	75
Committed	14
Planned	450
Solar	**88**
Existing	-
Committed and Planned	88
Total Renewable Resources	**16,084**

Source: OPA (Exhibit D-5-1, Table 3)

The implementation schedule for planned renewable resources is set out in Figure 4:

Figure 4: Planned Renewable Resources (Installed MW)



Source: OPA (Exhibit D-5-1, Figure 1)

The detailed break-down of the existing, committed and planned renewable resource mix is set out at Tables 9, 27, 28, 30, 31 and 33 of Exhibit D-5-1. The mix of programs will likely change as better opportunities present themselves.

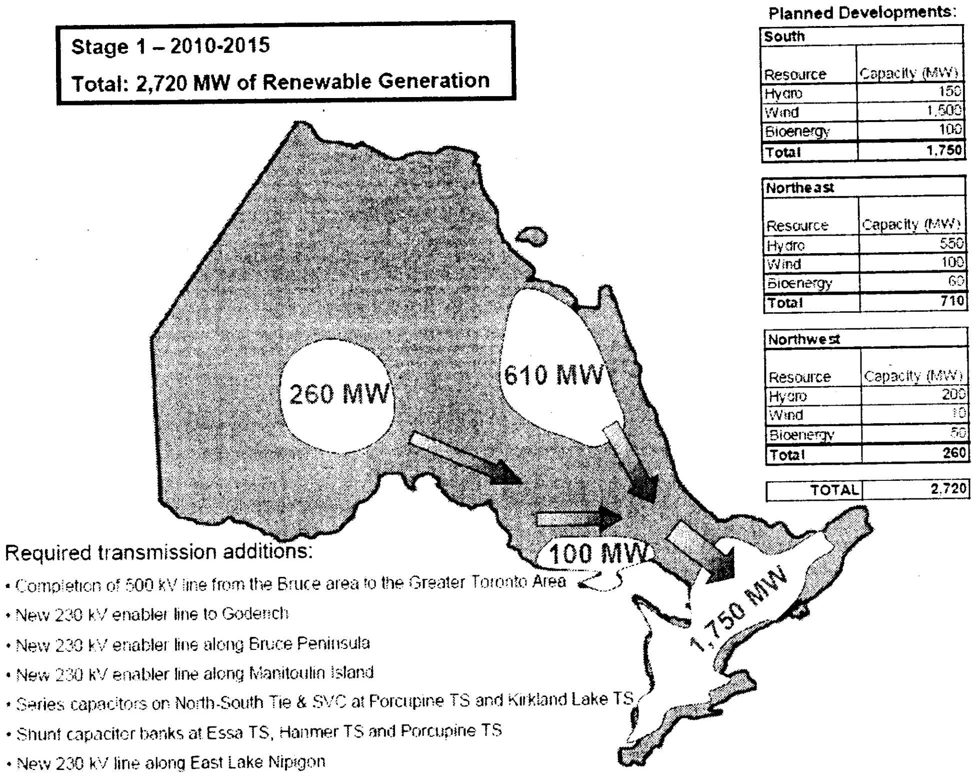
That mix will likely change as better opportunities present themselves and as progress with the implementation of transmission enhancements and enabler lines becomes clearer. All of the renewable resources to be procured by 2010 will be procured in accordance with Directives from the Minister of Energy. As a result, they will not be carried out in accordance with the procurement process for which the OPA is seeking OEB approval.

The staging of the planned renewables is closely linked to the development of enabling transmission reinforcement. Development is planned to occur in three stages, as presented in Figures 5, 6 and 7 as follows:

- Stage 1 adds about 2,720 MW of renewables resources over the period 2010-2015;
- Stage 2 increases planned renewables by 1,500 MW to a cumulative total of 4,220 MW, over the period 2016 to 2019; and

- Stage 3 further increases planned renewables by 2,280 MW to a cumulative total of about 6,500 MW, in 2020 and beyond.

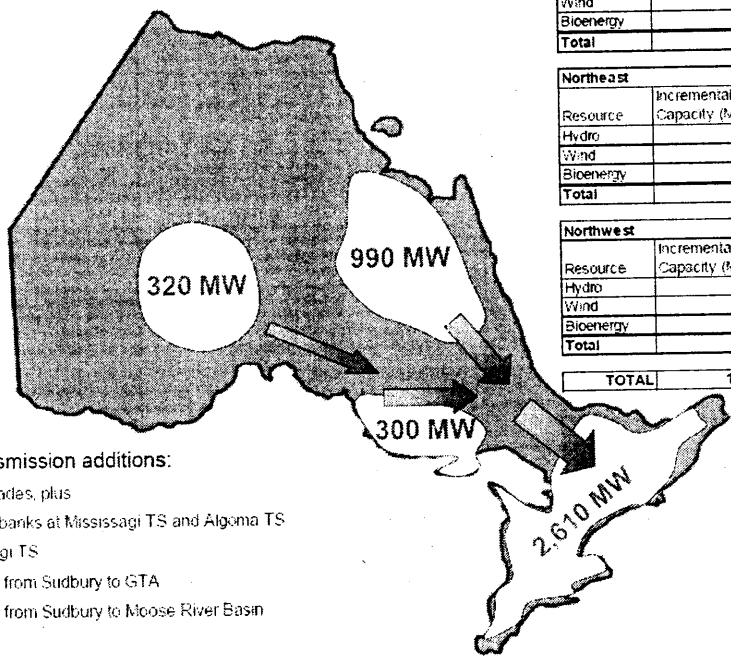
Figure 5: Planned Development of Renewable Resources – Stage 1



Source: OPA (Exhibit E-2-2, Figure 1)

1 **Figure 6: Planned Development of Renewable Resources – Stage 2**

Stage 2 – 2016-2019
Total: 4,220 MW of Renewable Generation



Planned Developments, in addition to Stage 1:

South		
Resource	Incremental Capacity (MW)	Cumulative Capacity (MW)
Hydro	0	150
Wind	700	2,200
Bioenergy	160	260
Total	**860**	**2,610**

Northeast		
Resource	Incremental Capacity (MW)	Cumulative Capacity (MW)
Hydro	350	900
Wind	200	300
Bioenergy	30	90
Total	**580**	**1,290**

Northwest		
Resource	Incremental Capacity (MW)	Cumulative Capacity (MW)
Hydro	40	240
Wind	10	20
Bioenergy	10	60
Total	**60**	**320**

TOTAL	**1,500**	**4,220**

Required transmission additions:

- All Stage 1 upgrades, plus
- Shunt capacitor banks at Mississagi TS and Algoma TS
- SVC at Mississagi TS
- New 500 kV line from Sudbury to GTA
- New 500 kV line from Sudbury to Moose River Basin

2 Source: OPA (Exhibit E-2-2, Figure 2)

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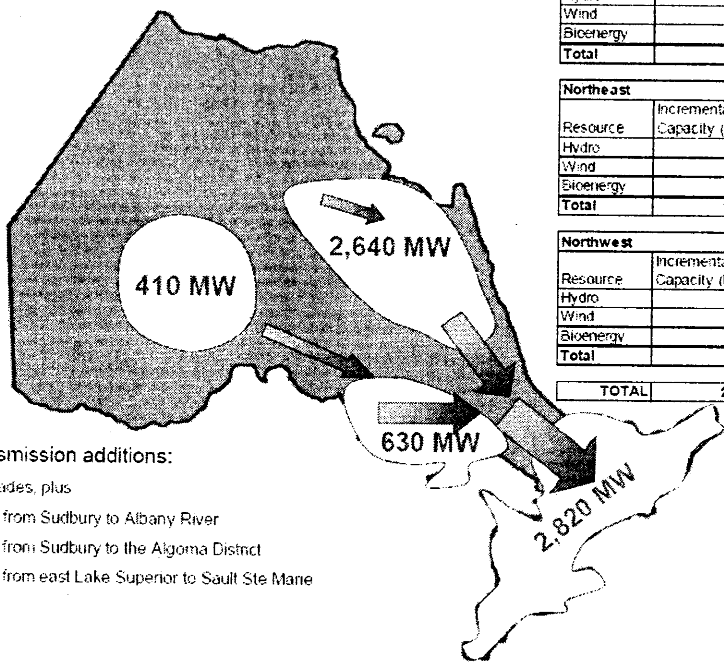
Figure 7: Planned Development of Renewable Resources – Stage 3

Stage 3 – 2020 and beyond
Total: 6,500 MW of Renewable Generation



Planned Developments, in addition to Stage 2:

South		
Resource	Incremental Capacity (MW)	Cumulative Capacity (MW)
Hydro	0	150
Wind	210	2,410
Bioenergy	0	260
Total	**210**	**2,820**

Northeast		
Resource	Incremental Capacity (MW)	Cumulative Capacity (MW)
Hydro	1,600	2,500
Wind	330	630
Bioenergy	50	140
Total	**1,980**	**3,270**

Northwest		
Resource	Incremental Capacity (MW)	Cumulative Capacity (MW)
Hydro	60	300
Wind	30	50
Bioenergy	0	60
Total	**90**	**410**

TOTAL	**2,280**	**6,500**

Required transmission additions:
- All Stage 2 upgrades, plus
- New 500 kV line from Sudbury to Albany River
- New 500 kV line from Sudbury to the Algoma District
- New 230 kV line from east Lake Superior to Sault Ste Marie

Source: OPA (Exhibit E-2-2, Figure 3)

Certain transmission development work will need to be initiated shortly to make the necessary transmission enhancements to meet the foregoing timetable. The specific transmission development work that is needed, the dates by which the development work must be commenced, and the estimated costs of the development work are addressed in the evidence relating to the applicable transmission projects.

5.0 NUCLEAR FOR BASELOAD

5.1 The Directive

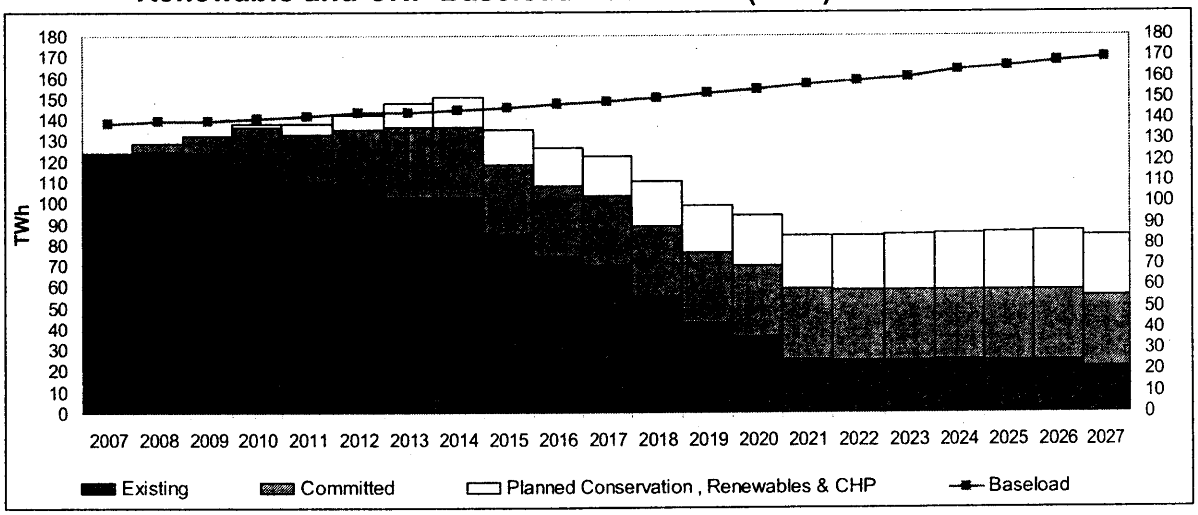
The Directive provides that the IPSP plan for nuclear power to meet baseload requirements but limit the installed in-service capacity to 14,000 MW. The Directive States:

> 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.

<u>Directive Priority</u>

The Directive priority is to first apply the feasible and economic contributions of Conservation and renewable supply to meet base-load requirements. After this contribution is taken into account, there is a gap. This gap is illustrated in Figure 8, which demonstrates the contribution of existing and committed resources as well as planned Conservation and renewable resources to meet baseload resource requirements.

Figure 8: Existing and Committed Baseload Resources + Planned Conservation, Renewable and CHP Baseload Resources (TWh)



Source: Exhibit D-6-1, Figure 8

As illustrated in Figure 8, after the contributions from existing and committed supply, planned Conservation and renewable resources are taken into account, there remains a baseload requirement of 85 TWh. That baseload requirement may be met by one of two candidates: nuclear power and combined cycle gas turbine generation ("CCGT"). In light of the OPA's planning criteria as addressed in Exhibit D-6-1, and the OPA's analysis in Exhibit D-3-1 Attachment 1, nuclear power is demonstrated to be the superior of those two candidates. The IPSP therefore plans for nuclear power to meet the remaining baseload requirements.

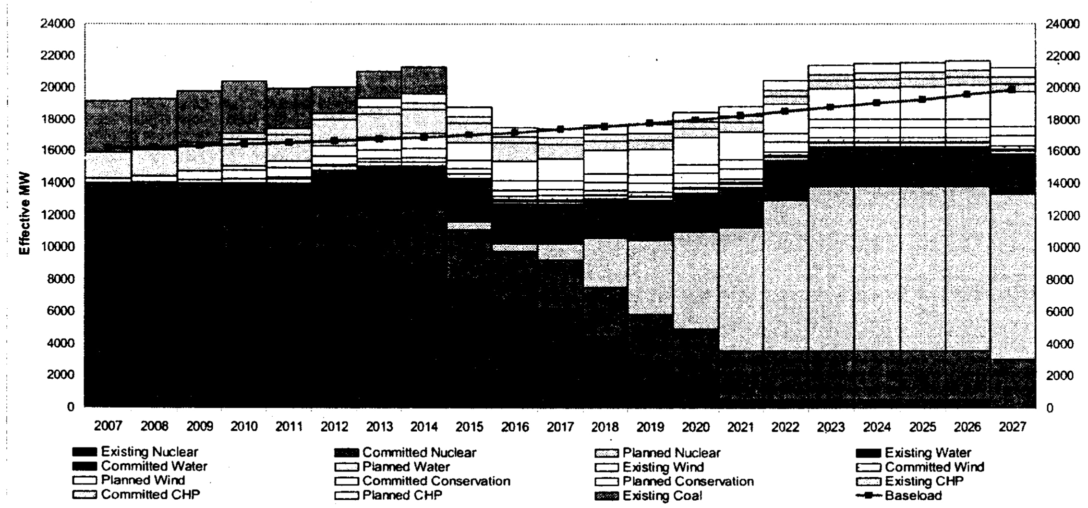
Implementation Priority

As indicated in the discussion respecting Directive Priority, nuclear power is preferable to CCGT for meeting baseload requirements. From an implementation perspective, the issue is whether the requirement for new nuclear resources should be met through refurbishment of existing nuclear plants ("refurbishment") or through building new plants ("new build"). Subject to economic viability, refurbishment is an attractive option for the following reasons:

- Compared to the new build option, refurbishment provides a shorter lead-time advantage as a result of unit refurbishment outages of two years or less;
- Refurbishment utilizes existing generation sites and transmission infrastructure thereby minimizing the associated environmental footprint;
- Local and surrounding community support for the continued operation of the Pickering, Bruce and Darlington generating stations is strong; and
- Experience from past and current refurbishment projects, both domestically and internationally, is leveraged on an on-going basis. This could result in improved project cost and schedules.

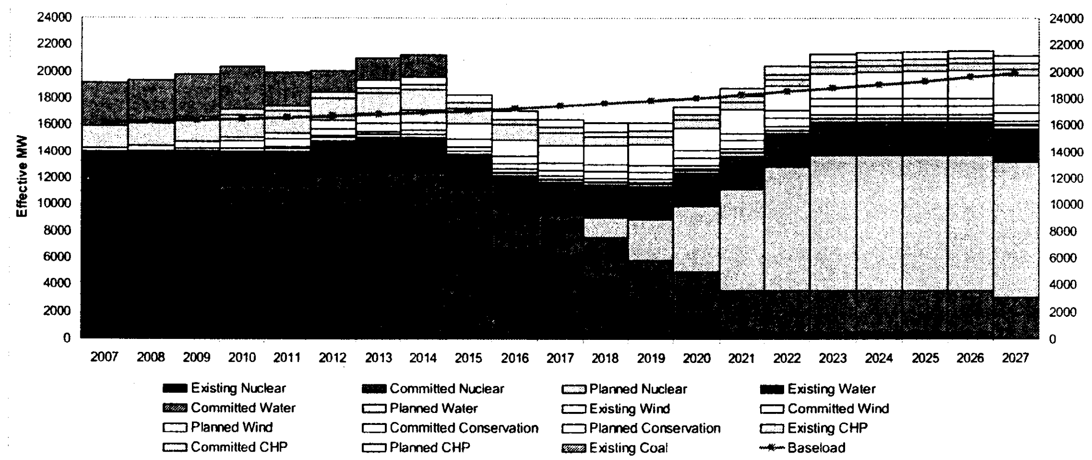
The most immediate implementation decision respecting refurbishment is with respect to Pickering B. The IPSP has built in the flexibility to address either scenario. If OPG decides to refurbish Pickering B, then the IPSP assumes that the associated capacity of 2,064 MW will be installed by 2018. This constitutes Case 1A under the IPSP. If OPG decides not to refurbish Pickering B, then the Plan assumes that the associated capacity of 2,064 MW will be replaced at a later time by new nuclear resources. This constitutes Case 1B under the IPSP. These cases are illustrated in Figure 9 and Figure 10, respectively, as follows:

Figure 9: Case 1A (with Pickering B Refurbishment): Resources to meet Baseload Requirements - Effective Capacity (MW)



Source: OPA (Exhibit D-6-1, Figure 4)

Figure 10: Case 1B (No Pickering B Refurbishment): Resources to meet Baseload Requirements – (Effective MW)



Source: OPA (Exhibit D-6-1, Figure 6)

To enable the retirement or the refurbishment of Pickering B, a new Oshawa transformer station may need to be built and brought into service by 2015. The details of this project, including the necessary transmission development work, are addressed in Exhibit E-4-1.

The OPA does not intend to procure any nuclear supply by the end of 2010.

6.0 COAL REPLACEMENT

6.1 The Directive

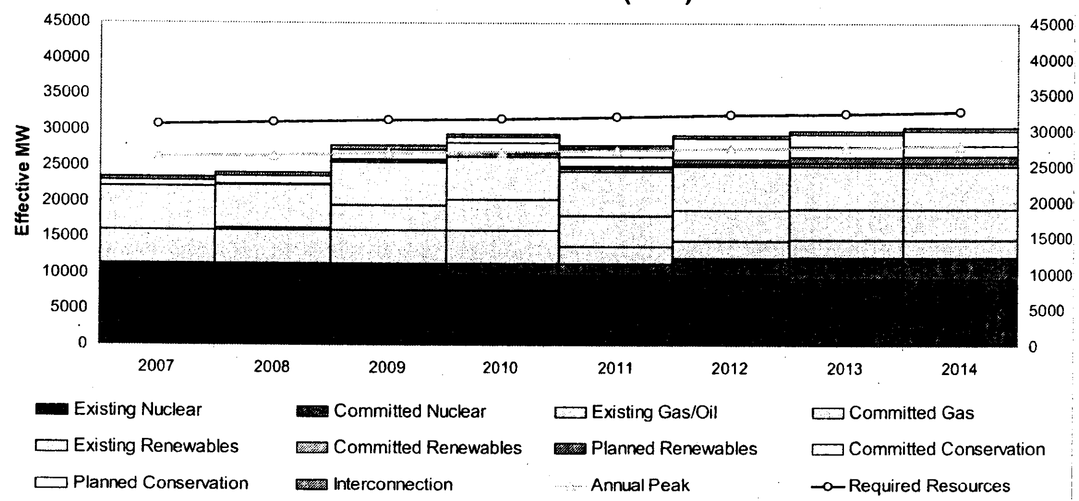
The Directive provides that the IPSP should plan for the replacement of coal-fired generation in the earliest practical time frame. It states:

> 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.

<u>Directive Priority</u>

The Directive priority is to first apply the feasible and economic contributions of Conservation and renewable supply to replace coal-fired generation. Figure 11, below, demonstrates the contribution of existing and committed resources as well as planned Conservation and renewable resources to meet the requirements currently met by coal-fired generation:

Figure 11: Contribution from Existing, Committed and Planned Conservation, Renewable, Nuclear, Gas/Oil & Interconnection Resources in the Absence of Coal-fired Resources (MW)



Source: Exhibit D-7-1, Figure 1

As illustrated in Figure 11, after all alternative resources are taken into account, and coal is removed, there remains a capacity gap. In addition, there is also a gap with respect to the contribution of coal-fired generation to energy production and system reliability. These contributions are discussed in Exhibit D-7-1. The only remaining resource with the characteristics to replace these contributions is gas-fired generation ("GFG"). As a result, replacing coal-fired generation will require an additional contribution from GFG, accompanied by any necessary transmission enhancements. There are different reliability requirements in the North West system and the remainder of the system. Each area, therefore, has to be looked at separately.

With respect to the North West, the IPSP plans for the replacement of the Atikokan and Thunder Bay coal-fired generation plants with a combination of Conservation and renewable resources to be available by 2014. With respect to the remainder of the system, the OPA considered a number of options for GFG to replace coal-fired generation in the earliest practical timeframe. These included consideration of existing gas-fired resources such as Lennox and Non-Utility Generators ("NUGs"), the potential expansion of existing GFG sites or facilities, addition of local GFG, and the conversion of coal-fired generating units to GFG.

Based on this assessment, three candidate options were identified:

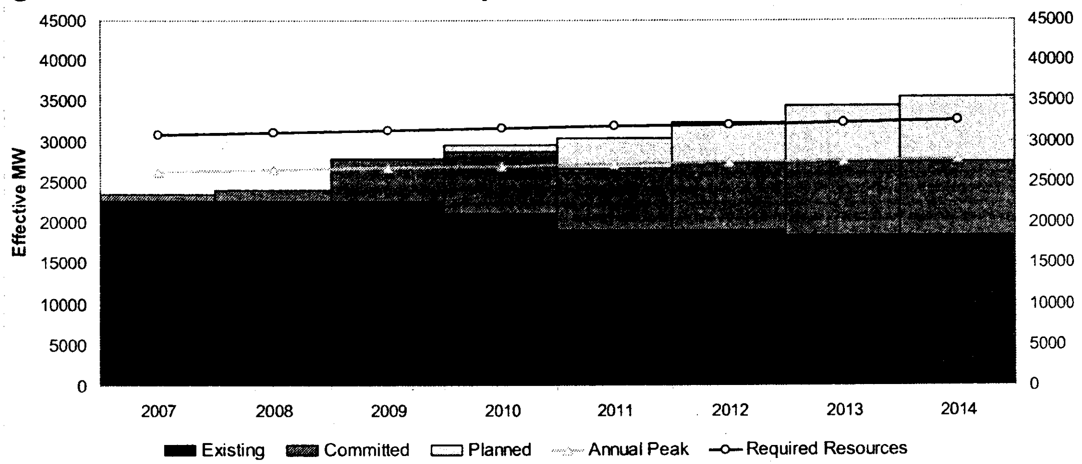
- GFG located near existing gas supply and infrastructure (i.e., the Sarnia area Dawn Hub, the location in Ontario with the lowest commodity and gas transportation cost);
- GFG located where there are local area reliability needs, accompanied by relatively modest transmission system enhancements (i.e., Northern York Region ("NYR"), Kitchener-Waterloo-Cambridge-Guelph ("KWCG"), and the Greater Toronto Area (the "GTA")); and
- Conversion of coal-fired generating units to GFG. This option requires extensive associated transmission system enhancements where there are local area reliability needs.

The OPA's analysis in Exhibit D-7-1 demonstrates that, in light of the OPA's planning criteria, among these three candidates, the installation of 1,400 MW of GFG to meet local area reliability needs in NYR, KWCG, and the GTA, accompanied by relatively modest transmission system enhancements, most effectively meets the Directive's requirements with respect to replacement of coal-fired generation.

Implementation Priority

As indicated above, local GFG is planned for the energy and capacity production contributions for coal-fired generation to be replaced by 2012. The reliability contribution will be replaced by these and other facilities by 2014. This replacement schedule is illustrated by Figure 12:

Figure 12: Resources to Allow Replacement of Coal-fired Resources (MW)



Source: OPA (Exhibit D-7-1, Figure 3)

In addition, to enable coal replacement, certain enhancements to the transmission system are needed in the Thunder Bay area. The details of these enhancements, including the necessary transmission development work, are addressed in Exhibit E-6-1.

As a result, the OPA intends to implement the coal replacement requirements of the Directive by procuring 1,400 MW of GFG to meet local area reliability needs (in NYR, KWCG, and the GTA) in accordance with the OEB-approved procurement process. Further details with respect to these procurements are provided in Exhibit D-10-1.

7.0 GAS FOR PEAK, HIGH EFFICIENCY AND HIGH VALUE USE

7.1 The Directive

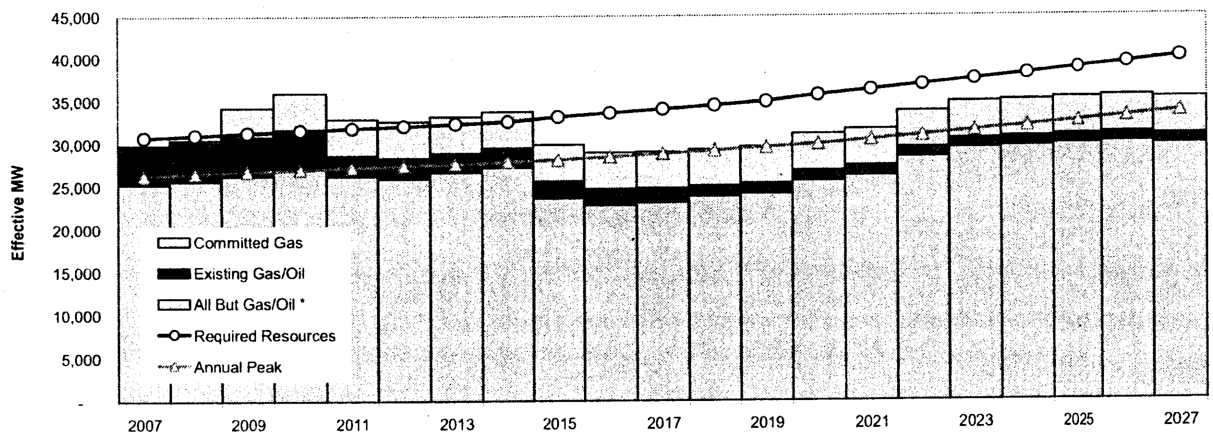
The Directive states:

> 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.

<u>Directive Priority</u>

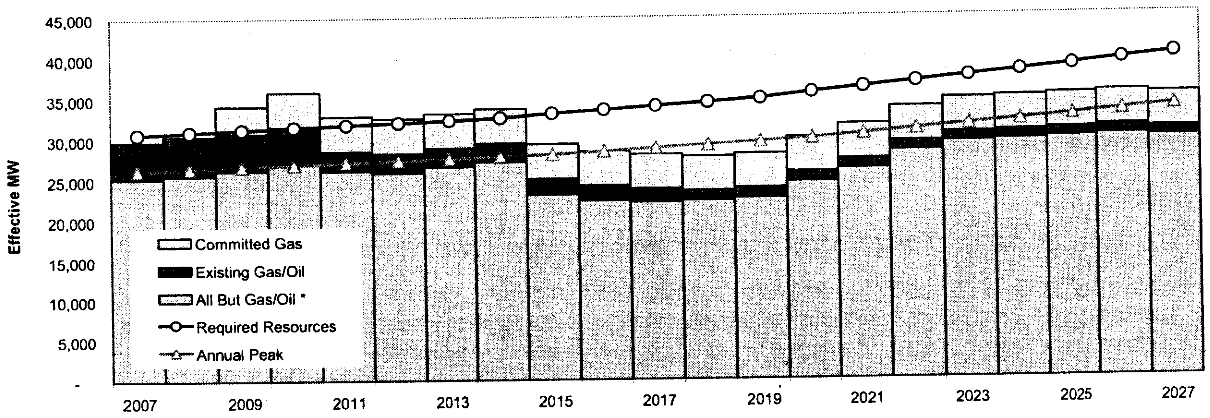
The Directive priority is to first apply the feasible and economic contributions of Conservation and renewable supply to meet peaking requirements. The contribution from nuclear power is then added. After these contributions are taken into account, there is a gap to be met by GFG. This gap is illustrated in Figure 13 and Figure 14, which demonstrate the contribution of these resources to meeting intermediate/peaking requirements under Case 1A (with Pickering B refurbishment) and Case 1B (without Pickering B refurbishment)

Figure 13: Required Gas-Fired Resources – Assuming Pickering B Refurbished (Effective MW)



Source OPA (Exhibit D-8-1, Figure 2)

Figure 14: Required Gas-Fired Resources – Assuming Pickering B Not Refurbished (Effective MW)



Source: OPA (Exhibit D-8-1, Figure 3)

As illustrated in Figures 12 and 13 after the contribution of existing, committed and planned resources, there remains a requirement for GFG.

In order to maintain the contribution by GFG to peaking, high value and high efficiency uses, the use of gas in the IPSP is restricted as much as possible to either simple cycle gas turbines ("SCGT") or CCGT.

<u>Implementation Priority</u>

As discussed above, GFG also contributes to meeting local area requirements, and to replacing the contribution of coal-fired generation. GFG will also be used when alternative resources are not feasible or cost effective. The IPSP also includes a certain amount of "proxy gas" to represent unspecified supply resources indicated for the long term, that will not necessarily prove to be gas-fired, but are modelled as if they will be.

When gas-fired resources are used, they are generally planned to be SCGT, to meet peaking requirements, or CCGT, to meet intermediate requirements. The Plan also includes combined heat and power ("CHP", also known as cogeneration) resources, that meet baseload requirements, where the amount included in the Plan is that expected to materialize from OPA procurement programs. There are also a number of gas-fired generators, known as non-utility generators or NUGs, which are assumed to operate as baseload resources because of the contractual terms of their current NUG contracts. The Plan assumes that for the NUG contracts that expire by 2015, the associated capacity will continue, but will meet intermediate and peaking load requirements, depending on whether the NUGs are CCGT or SCGT resources, respectively.

The current list of contracts and projects through which the IPSP intends to meet the GFG requirements is set out in Table 4, below:

Table 4: Allocation of Planned Gas-Fired Resource Requirements

	Pickering B Refurbished			Pickering B Not Refurbished		
Project/Site	**Generation Type**	**MW**	**In-Service**	**Generation Type**	**MW**	**In-Service**
Lennox	CST	2,100	2011	CST	2,100	2011
CHP	CHP	586	2013	CHP	586	2013
Northern York Region	SCGT	350	2011	SCGT	350	2011
Kitchener-Waterloo-Cambridge-Guelph	SCGT	450	2012	SCGT	450	2012
Southwest GTA	CCGT	850	2013	CCGT	850	2013
GTA	SCGT	550	2014	SCGT	550	2014
NUG Replacement	SCGT/CCGT	469	2013 +	SCGT/CCGT	1,368	2013 +
Unspecified/Proxy Gas	SCGT/CCGT	650	2018+	SCGT/CCGT	825	2017 +
	Total	**6,005**		**Total**	**7,079**	

Source: OPA (Exhibit D-8-1, Table 9). Southwest GTA may be met by either CCGT or SCGT, but was modelled as CCGT. Likewise, GTA could be met by either type, but was modelled as SCGT. CST is the acronym for "Condensing Steam Turbine"

This mix will likely change as better opportunities present themselves.

Some of these projects/sites will be procured by the end of 2010 in accordance with the OEB-approved procurement process. These are: Northern York Region, Kitchener–Waterloo-Cambridge-Guelph, and the GTA (as discussed above). In addition, another facility, the Lennox Generating Station, operates under a Reliability-Must-Run contract with the IESO. The contribution from that facility will also be procured by the OPA. This is described in greater detail in Exhibit D-8-1, Attachment 1 and Exhibit D-10-1.

8.0 NEAR-TERM ACTION PLAN

The Directive and Implementation Priorities lead to both near-term and longer-term action plans. As indicated in the introduction, the IPSP identifies specific priorities for the near-term, but will, more generally, develop options for the mid-term and explore opportunities for the longer-term.

This leads to a near-term action plan that the OPA will carry out over the 2008 to 2010 period to implement the IPSP. That near-term action plan has the following components:

- Conservation: The OPA will, through resource acquisition and under existing government Directives, procure approximately 1,400 MW of Conservation resources. It will also invest in market capability and market transformation activities;
- Renewable Supply: The OPA will, under existing government Directives, procure up to 2,700 MW of renewable resources; and
- Gas Fired Generation: The OPA will, through an OEB-approved procurement process, procure gas-fired projects that are required for local area supply and transmission relief. The capacity targets for these projects are as follows: (1) 850 MW of CCGT capacity in the Southwest GTA; (2) 550 MW of SCGT capacity in the GTA, (3) 350 MW of SCGT capacity in Northern York Region; and (4) 450 MW of SCGT capacity in Kitchener-Waterloo-Cambridge-Guelph. In addition, the OPA will enter into a procurement contract with OPG to replace the OEB-approved Reliability-Must-Run contract that is currently in place with respect to the Lennox GS.

In addition, it will be necessary for transmission proponents to carry out development work with respect to the transmission projects recommended in the IPSP. Certain of these projects, in addition to meeting the Directive's supply mix goals, are aimed at ensuring regional and local area reliability (i.e., Windsor Essex, Central and Downtown Toronto, and Milton Transformer Station). The recommended transmission projects, and the necessary development work, are referred to above and are addressed in more detail in the supporting evidence relating to the individual projects. It is not expected that any of these projects will result in a leave-to-construct application before the OEB during this near-term period.

9.0 CONCLUSION

The OPA's Plan to achieve the Directive's goals involves prioritizing how Conservation and supply resources should be acquired through (i) meeting the requirements of the Directive in light of the OPA's planning criteria (the "Directive Priority"); and (ii) the sequencing of installing resources, especially in light of long lead times and necessary transmission enhancements (the "Implementation Priority").

With respect to the Directive Priority, the IPSP ensures that the identified resource goals in the Directive are met by identifying the priority order in which the resources are planned to meet the electricity needs of the province as follows:

1. Maximize feasible cost effective contribution from energy efficiency, demand management, fuel switching, and customer based generation (Conservation);
2. Maximize feasible cost effective contribution from renewable sources;
3. Make up baseload requirements remaining after Steps 1 and 2 above with nuclear power;
4. Replace coal-fired generation with power from committed and planned resources. Specifically, in order to ensure that existing coal-fired facilities are replaced by 2014, gas-fired generation ("GFG") facilities are planned to be installed in the areas of Northern York Region, Kitchener-Waterloo-Cambridge-Guelph and the Greater Toronto Area ("GTA") by 2014; and
5. Restrict contribution of GFG to specific projects as required when additional Conservation and renewable resources are not feasible or cost effective.

The Directive Priority is accompanied by an Implementation Priority. The Implementation Priority is the relative chronological ordering of resource additions. The IPSP is the combination of the Directive Priority and the Implementation Priority. It is set out in summary form in Table 5, below.

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1 **Table 5: Summary of the IPSP**

Subject of Directive	Directive Goals	Directive Priority	Implementation Priority	Current Mix of Projects/ Facilities/ Programs (Evidence Reference)	Procurement Authorization (for resources to be acquired by end of 2010)
Conservation	2010: 1,350 MW 2025: an additional 3,600 MW	Maximize feasible cost effective contribution from Conservation before supply resources.	2010 goals to be met through resource acquisition; experience with programs to provide information on how to economically meet and exceed 2025 goal using combination of resource acquisition, capability building and market transformation programs.	2010: Exhibit D-4-1, Table 21 2025: Exhibit D-4-1, Table 22	Government Directives
Renewable Supply	10,402 MW by 2010 15,700 MW by 2025	Maximize feasible cost effective contribution from renewable sources before other supply resources in the following order of economic priority: hydro, bioenergy, and wind.	2010: All feasible renewable resources that can be installed prior to 2010 should be acquired; 2025 goal to be met by first applying all feasible hydro resources (2,921 MW); all feasible bioenergy (450 MW); and all small, standard offer wind projects (1,148 MW). The remainder of the goal (1,891 MW) to be made up of large wind projects. The order of implementation will be coordinated with necessary transmission enhancements.	2010: Exhibit D-5-1, Table 1 2025: Exhibit D-5-1, Tables 2, 19, 31, and 33.	Government Directives
Nuclear for Baseload	Up to 14,000 MW	Make up remaining baseload requirements remaining after Conservation and renewable supply with nuclear supply. Refurbished	10,249 MW of nuclear capability required, either from refurbishments or new build. Depending on refurbishments, new nuclear capacity of 1,400 MW to 3,400 MW, starting in 2018.	Exhibit D-6-1 Table 14	No Procurements Planned

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Subject of Directive	Directive Goals	Directive Priority	Implementation Priority	Current Mix of Projects/ Facilities/ Programs (Evidence Reference)	Procurement Authorization (for resources to be acquired by end of 2010)
		nuclear facilities have planning advantages and are generally preferred to new nuclear facilities. However, each case is fact dependent.			
Replacement for Coal Fired Generation	Replace coal-fired generation in earliest practical timeframe.	Replacing coal-fired generation requires replacing its three types of contributions to Ontario's electricity needs: capacity (6,434 MW), energy production (24.7 TWh) and reliability (flexibility, dispatch ability, and ability to respond to unforeseen supply availability).	15,000 MW of resources are planned by 2015, partly to replace coal, partly to meet growth, and partly to catch up with deficiencies that existed in the beginning of the planning horizon. Gas-fired generation will be installed in the areas of York Region, Kitchener Waterloo and Southwest GTA. This will allow for the energy and capacity production contributions to be replaced by 2012. The reliability contribution will be replaced by these and other facilities by 2014.	Exhibit D-7-1, Table 5	Conservation and Renewable Resources: Government Directives GFG: OEB Approved Procurement Process
Natural Gas	Confine gas to peaking, high value and high efficiency uses.	Gas fired generation will be used to meet peak and intermediate requirements and to provide flexibility. When gas-fired resources are used, they should be restricted as much as possible to either simple cycle gas generation (to meet peaking	In addition to meeting the local area supply requirements in York Region, Kitchener-Waterloo and Southwest GTA, current facilities that operate as baseload may be converted to meet intermediate and peaking needs and energy will be procured from Lennox GS to replace the Reliability Must Run Contract with the IESO. An additional 400-650 MW of	Exhibit D-8-1, Table 9	OEB Approved Procurement Process

Subject of Directive	**Directive Goals**	**Directive Priority**	**Implementation Priority**	**Current Mix of Projects/ Facilities/ Programs (Evidence Reference)**	**Procurement Authorization (for resources to be acquired by end of 2010)**
		requirements) or combined cycle gas generation (to meet intermediate requirements). Any new contracts and facilities should reflect these requirements as much as possible.	"proxy gas" may be required around 2017.		

1

NORTHERN YORK REGION

1.0 EXECUTIVE SUMMARY

The OPA recommends the siting of new gas-fired generation in Northern York Region (NYR) and intends to procure such generation for a projected in-service date of the end of 2011.

The purpose of gas-fired generation in NYR is to address two needs: a capacity need that will arise in 2013, and a security need that is present today. It will also further the Directive's goals of using gas for high value and high efficiency applications and replacing coal with cleaner sources in the earliest practical timeframe.

NYR has experienced robust growth in the past few years and this has resulted in the area's demand exceeding the capability of the electrical infrastructure serving the area. There are four electrical service needs identified for NYR. They are:

a) inadequate supply capacity;
b) inadequate transformation capacity at Armitage Transformer Station (Armitage TS);
c) a lack of supply diversity; and
d) insufficient distribution feeder positions at Armitage TS for expansion.

In the past two years, Hydro One Networks has implemented near-term reinforcement measures including the addition of shunt capacitors to increase the supply and transformation capacity. It has also been seeking environmental assessment ("EA") approval for the construction of the new Holland Junction Transformer Station in King Township. This station will alleviate the transformation and the distribution feeder position needs. The OPA and the LDCs serving the NYR have also implemented a number of conservation and distributed generation measures to supplement the supply capability. Together, these measures will address the capacity needs in NYR until about 2013, although the security need remains to be addressed.

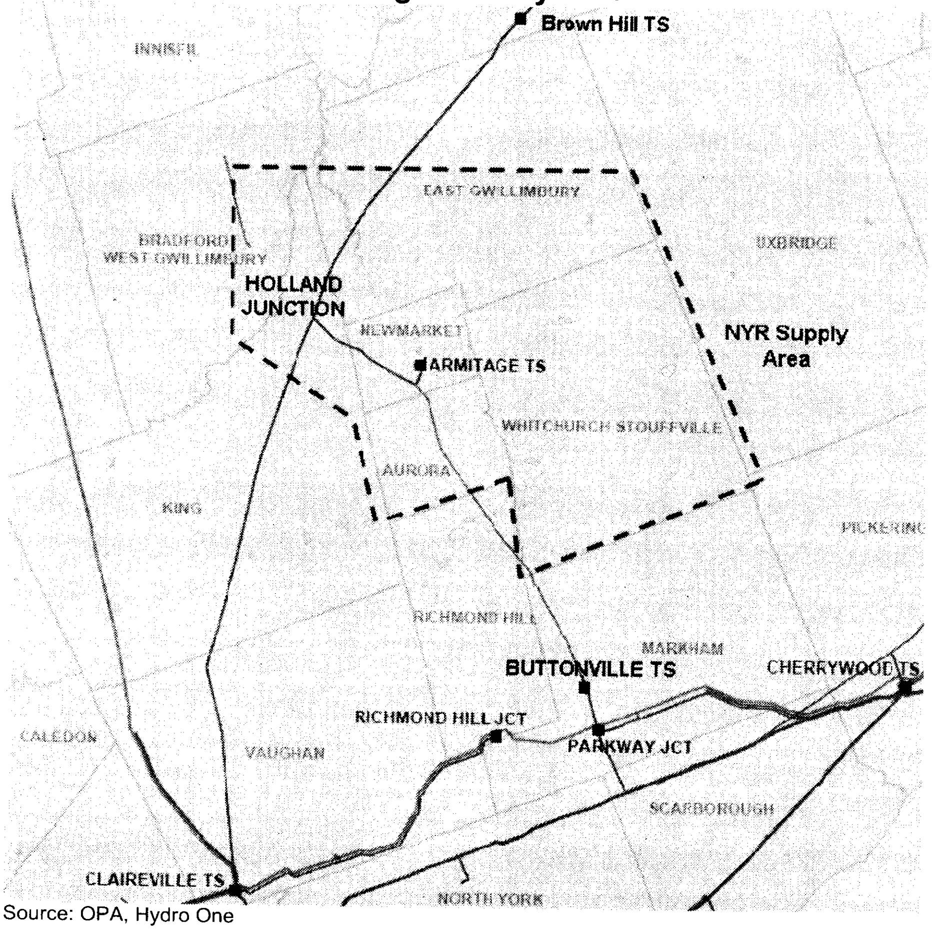
The OPA recommends that gas-fired generation be built in NYR to address the supply capacity and security needs as early as practical. Based on the lead-time required to develop major supply options, the earliest in-service date is estimated to be the end of 2011. As noted, the proposed generation will address both the local area need and the Directive's goals of using gas at peak times for high efficiency and high value applications, as well as replacing coal. Gas generation also offers cost, feasibility, flexibility, environmental performance and societal acceptance benefits. The OPA therefore intends to procure gas-fired generation in NYR.

2.0 PROJECT LOCATION & OVERVIEW

As identified in the OPA's report 'Northern York Region Electricity Supply Study' submitted to the OEB on September 30, 2005, York Region is a rapidly growing community with a population of roughly 960,000 in 2006. While the southern portion of York Region had its electricity infrastructure upgraded in 2004, the northern portion has continued to grow without major improvements since the 1990s. The focus of the 2005 study was on the more urgent needs of the northern half of this region, specifically the communities served from Armitage TS. This station supplies six York region municipalities: Aurora, East Gwillimbury, Georgina, King, Newmarket, and Whitchurch-Stouffville, as well as Bradford West Gwillimbury in Simcoe County.

A map of the area of focus for this study is provided below at Figure 1. The demarcated area on the map is defined collectively herein as "Northern York Region" or "NYR".

Figure 1: Northern York Region Study Area



Source: OPA, Hydro One

3.0 EXISTING FACILITIES

NYR is a summer peaking area with close to 400 MW of load. The primary supply to this load is from Armitage TS. There are presently two transformer groups at Armitage TS: "Armitage 1" and "Armitage 2". These groups are relatively independent in operation, but have some support systems in common and some capability to back each other up. Armitage TS supplies sixteen feeders at the distribution level. Presently, six are allocated to Newmarket Hydro, three to PowerStream, and seven to Hydro One Distribution.

The 230 kV transmission in the area consists of one double-circuit 230 kV line, B82V/B83V, that connects Claireville TS in Vaughan to Brown Hill TS in Georgina. At Holland Junction in King Township, an eight kilometre line tap connects Armitage TS in Newmarket to this main supply line, as shown in Figure 1.

There is also one gas-fired generating plant located in the NYR service area at the Keele Valley Landfill site. It currently supplies about 19 MW of power and is connected to a 44 kV feeder which feeds directly into Armitage TS.

4.0 ASSESSMENT OF NEED

For assessing the supply adequacy at Armitage TS, the forecast demand at peak for the NYR service area was examined. The amount of available local resources was then deducted, and the remaining load was compared to the supply capability of the area. The determination of need was consistent with the assumptions, considerations and criteria contained in the IESO Ontario Resource and Transmission Assessment Criteria (Exhibit E-7-1, Attachment 3).

4.1 Historical Growth and Forecast Demand

The demand in NYR has seen a robust rate of growth of about 4% over the last four years, as shown in Table 1 and Figure 2. The local distribution companies, Newmarket Hydro, PowerStream and Hydro One Distribution, forecast an overall growth rate of approximately 3.1% for NYR for the next ten years in their recent (June 2007) load forecasts. For area planning purposes, the summer peak demand assumed is based on extreme temperature conditions, consistent with the IESO Ontario Resource and Transmission Assessment Criteria. Typically, the peak demand under this condition is about 6% higher than under normal peak summer temperature conditions.

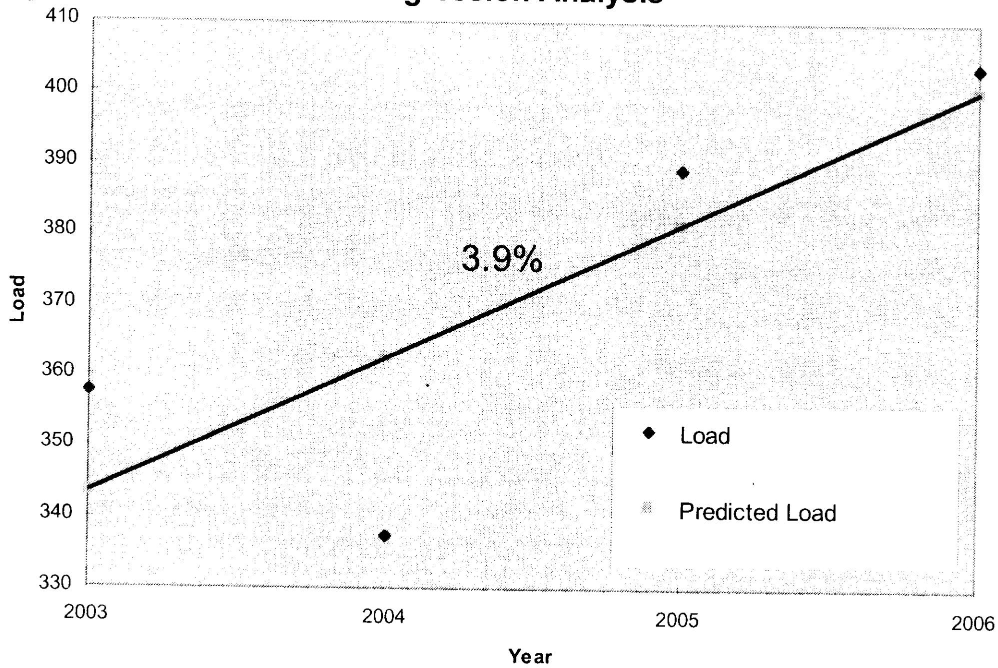
Individually, Newmarket Hydro, PowerStream and Hydro One Distribution forecast their loads to grow at approximately 3%, 3.5% and 2.9%, respectively, without adjusting for load transfers. In the past years, load was transferred to neighbouring stations due to inadequate supply capacity in NYR. For determination of supply need, the assumption is that, once there is sufficient capacity in NYR, the load that was transferred out of the NYR service area will be returned. In addition, roughly 10 MW of external load is expected to be transferred to the area to optimize the region's overall supply. The repatriation of load and additional transfer is not expected to occur until additional supply is added around the end of 2011, at which point this load can be supplied reliably. See Table 2 for a detailed 10 year load forecast for NYR.

Table 1: Northern York Region Historical Load

Entity	2003 Actual (MW)	2004 Actual (MW)	2005 Actual (MW)	2006 Actual (MW)	Average Growth
Total Area Demand	**358**	**337**	**389**	**404**	**4.1%**
Adjusted Load - Transfers	-	-17	-17	-17	-
Net Demand	**358**	**320**	**372**	**387**	**2.6%**

Source: OPA, Hydro One, PowerStream, Newmarket Hydro

Figure 2: Historical Load Regression Analysis



Source: OPA

Table 2: Northern York Region Forecast Load

Entity	2007 (MW)	2008 (MW)	2009 (MW)	2010 (MW)	2011 (MW)	2012 (MW)	2013 (MW)	2014 (MW)	2015 (MW)	2016 (MW)	2017 (MW)	Average Growth
Newmarket	163	169	175	181	187	194	200	208	215	217	220	**3.0%**
PowerStream	100	105	110	115	120	124	128	132	136	140	142	**3.5%**
Hydro One Distribution	160	164	169	174	179	184	189	195	200	206	212	**2.9%**
Total Area Demand	**423**	**438**	**454**	**470**	**486**	**502**	**517**	**535**	**551**	**563**	**573**	**3.1%**
Adjusted Load - Transfers	-17	-30	-30	-30	-30	10	10	10	10	10	10	-
Net Demand	**406**	**408**	**424**	**440**	**456**	**512**	**527**	**545**	**561**	**573**	**583**	**3.7%**

Source: OPA, Hydro One, PowerStream, Newmarket Hydro

4.2 Supply Capability and Needs

In assessing the adequacy and reliability of the Armitage supply, the OPA relies on reliability standards and criteria, as described in Exhibit E-2-7. To test the reliability of the system, the contingencies considered for NYR supply are as follows:

- loss of one of the two 230 kV supply circuits [N-1];
- loss of one of the four step-down transformers [N-1]; and
- loss of the double-circuit 230 kV line [N-2].

The first two are referred to as single-element or [N-1] contingency events, and the last is referred to as a double-element or [N-2] contingency event.

For the application of the reliability criteria in the planning of NYR service needs, load meeting capacity (LMC) is defined as the maximum load in the area that can be served so that following the critical single-element or [N-1] contingency, the system is stable, all equipment is within its rating, voltages are within the acceptable operating range, and no load is interrupted. Similarly, supply security is the ability of the delivery system to restore interrupted load in a reasonable time following the critical double-element or [N-2] contingency. The application of the security criterion indicates when an area would require an alternative source of supply or the need for greater diversity of supply.

Due to large and sustained load growth over the past years, the demand in NYR has exceeded the capability of the existing supply. As discussed below, there are four needs identified for NYR:

a) inadequate supply capacity;
b) inadequate transformation capacity at Armitage TS;
c) a lack of supply diversity; and
d) insufficient distribution feeder positions at Armitage TS for expansion.

4.2.1 Supply Capacity

As described above, the two [N-1] contingency events that are critical to determining the capacity of the Armitage supply are the loss of one of the two 230 kV supply circuits and the loss of one of the four step-down transformers. Each of the two 230 kV circuits supplying Armitage TS can supply about 400 MW each. The nominal capacity of each of the four step-down transformers at Armitage TS is 125 MVA.

Following the loss of one of the 230 kV circuits, B82V or B83V, circuit breakers at Claireville, Brown Hill, and Armitage TS would open to isolate the faulted circuit. This would also result in the loss of two transformers connected to that circuit at Armitage TS, leaving the total station load now supplied from the remaining 230 kV circuit and the two transformers. The most restrictive limits in this case are the Long Term Emergency Rating ("LTR") and maximum voltage drop limit. Both limit the LMC of Armitage TS to 340 MW. Reliability standards and criteria indicate that no load should be lost for this outage. Therefore, additional supply is required when the load supplied by Armitage TS exceeds 340 MW. This limit was exceeded by 2003, as shown in Table 1. There are also three less restrictive limits for this contingency:

- the point at which the steady voltage in NYR is near instability, about 380 MW prior to the addition of Holland TS and roughly 480 MW afterwards;
- the thermal capability of B82V/B83V between Woodbridge Junction and Holland Junction which limits the NYR load to approximately 420 MW; and
- the summer thermal rating of the 230 kV tap to Armitage which is approximately 440 MW.

The voltage instability limit of 380 MW has been exceeded and increasing load continues to approach the thermal capabilities.

There is also a transformation capacity limit so as to maintain safe operation of the remaining equipment for the loss of a transformer at Armitage TS. Immediately following the loss of one of the transformers, the protection system would open the transformer's supply line and the other transformer sharing this circuit. Supply at Armitage TS is limited by the 10 day LTR of 340 MW. Reliability standards and criteria require that no load should be lost for an [N-1] outage, so additional transformation capacity is required when the load exceeds 340 MW. As shown in Table 1, Armitage TS has been subjected to loading beyond this limit since 2003. Any load exceeding this limit would have to be interrupted following a contingency.

4.2.2 Supply Security

The most critical line section for an [N-2] contingency in NYR is between Armitage TS and the tap point at Holland Junction. All load in NYR, other than load that can be transferred to adjacent supply points through the distribution system, would be interrupted until the line is repaired as there is no supply alternative for Armitage TS. If a contingency occurs on the line section between Claireville station and Holland Junction, about 100-150 MW can be supplied from Brown Hill, once the faulted section is isolated. However, rotational load interruptions would occur for the remaining load (i.e., approximately 250-300 MW in 2007) until the line is repaired. For the loss of the line north of Holland Junction, all of the power to Armitage TS can be provided from the Claireville station, after the faulted line section has been isolated.

The current supply to Armitage TS does not meet the security specifications for [N-2] contingencies as laid out in the IESO's Ontario Resource and Transmission Assessment Criteria. Even with generation at Keele Valley operating and load transfers on the distribution system, it is not possible to restore the area load within the time frames specified in Exhibit E-2-7. In fact, for the worst contingency, loss of the Armitage tap, it is not possible to restore any load until the line is back in-service. This means that in 2007 approximately 400 MW of load could be without power for eight hours or more.

4.2.3 Distribution Considerations

One other consideration with regard to supply capability is the loading on the distribution system. Each distribution feeder has a planned loading of about 23 MW based on Hydro One Distribution guidelines. Exceeding this level could result in lower than planned voltages at the end of the feeder and a lack of transfer capability under feeder outage situations. The addition of new feeders at a station is limited by the number of 44 kV breaker positions available and the transformation capacity. Armitage TS is limited to 16 breaker positions, all of which are currently utilized. Existing feeders have exceeded their planned capacity, and with the load growth shown in Table 2, new feeder capacity is required to meet the needs of LDCs. For a station load of 387 MW, as recorded in the summer of 2006, and assuming the load is evenly distributed, the feeder loading is close to 24 MW per feeder. The need for additional feeders will necessitate new feeder positions at a new station (since Armitage TS is limited to sixteen feeder positions).

5.0 DEVELOPMENT OF ALTERNATIVES

5.1 Near-Term Transformation and Distribution Reinforcements

The OPA's 2005 report to the OEB identified the need for a new transformer station in the vicinity of Holland Junction as the preferred method of addressing the near-term transformation and distribution needs. Subsequently, the OEB issued an Order to Hydro One Networks to proceed with the development of this station. Hydro One Networks has recently received EA approval for a site near Holland Junction. The current probable in-service date is before the summer of 2009. As detailed in the System Impact Assessment (SIA) in Attachment 1 to this exhibit, the proposed Holland TS will connect along B82V/B83V near the Armitage Tap. As the station will be able to connect to the main 230 kV line, rather than the tap, this station will avoid using up capacity on the Armitage tap and will lessen the risk of voltage collapse (as it is electrically closer to the Claireville station supply source) following an [N-1] circuit outage. Holland Junction TS is also centrally located to growing loads in the northern part of NYR. This station will provide relief for NYR's immediate transformation and feeder position needs. These near-term reinforcements will not address the other identified security and supply adequacy needs.

5.2 Distributed Generation and Conservation

The OPA and LDCs have explored distributed generation and Conservation opportunities in the area to help address the need for additional supply. Preliminary estimates from the LDCs indicate distributed generation potential of close to 21 MW by 2008: 12.5 MW of currently unused gas-fired capacity is expected to come online at Keele Valley; 6 MW has been identified by aggregators in NYR; and, an additional 2.7 MW at a water pumping station in Aurora.

Table 3: Distributed Generation in NYR

Source	Amount (MW)
Keele Valley	12.5
Aggregated generation	6
Water pumping station	2.7
Total DG	**21.2**

Source: OPA

As well, a number of Conservation programs and initiatives are presently underway. The regional share of the 6,300 MW provincial Conservation target was disaggregated for NYR based on the methodology described in Exhibits D-4-1 and E-2-3. The estimated Conservation potential for NYR increases from 9 MW in 2007 to 58 MW by 2017, as presented in Table 4. Based on these estimated levels, Conservation can contribute to meeting the need for additional supply.

Table 4: Northern York Region Conservation Estimate

	2007 (MW)	2008 (MW)	2009 (MW)	2010 (MW)	2011 (MW)	2012 (MW)	2013 (MW)	2014 (MW)	2015 (MW)	2016 (MW)	2017 (MW)
Cumulative Conservation	9	12	17	27	31	36	41	45	50	54	58

Source: OPA

Distributed generation and Conservation will reduce the need for other measures based on present estimates, but they will not fully address the need for additional supply on their own. Table 5 summarizes the load remaining after accounting for Conservation and distributed generation.

Table 5: Forecast Load after Conservation and DG

Entity	2007 (MW)	2008 (MW)	2009 (MW)	2010 (MW)	2011 (MW)	2012 (MW)	2013 (MW)	2014 (MW)	2015 (MW)	2016 (MW)	2017 (MW)	Average Growth
Newmarket	163	169	175	181	187	194	200	208	215	217	220	**3.0%**
PowerStream	100	105	110	115	120	124	128	132	136	140	142	**3.5%**
Hydro One Distribution	160	164	169	174	179	184	189	195	200	206	212	**2.9%**
Total Area Demand	**423**	**438**	**454**	**470**	**486**	**502**	**517**	**535**	**551**	**563**	**573**	**3.1%**
Cumulative Conservation	9	12	17	27	31	36	41	45	50	54	58	-
DG	10	21	21	21	21	21	21	21	21	21	21	-
Net Demand	**404**	**405**	**416**	**422**	**434**	**445**	**456**	**468**	**479**	**489**	**494**	**2.0%**
Adjusted Load - Transfers	-17	-30	-30	-30	-30	10	10	10	10	10	10	-
Net Total Area Demand	**387**	**375**	**386**	**392**	**404**	**455**	**466**	**478**	**489**	**499**	**504**	**2.7%**

Source: OPA

Several other distributed generation options were considered but eliminated as not being feasible for addressing the needs in this area:

- Wind generation was not considered in NYR, as no capability was identified; and
- Hydroelectric generation was not evaluated as a viable option for meeting any of the needs, as no potential was identified in the area.

5.3 Future Transformation and Distribution

A second new station will be required by roughly 2015 to meet the needs of the area over the longer-term. Depending on the preferred supply alternative, the LDCs will choose a location for the second transformer station. There is sufficient time to address the next station in the subsequent IPSP as part of regional plans.

5.4 Major Supply Reinforcement Need Date

With the transformation and distribution needs addressed in the near-term, the need for additional supply capability and the need for an alternative supply source both remain. The need date based on supply adequacy consideration is 2013. This assumes that: the load

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will be as forecasted in Table 2; it is possible to sustain load transfers at neighbouring stations; the estimated amount of conservation and distributed generation will be developed; Holland Junction Station will be in-service as soon as possible; and, the other near-term transmission and distribution measures will be implemented. If less Conservation or distributed generation materializes, load transfers cannot be sustained, or near-term measures are not implemented as planned, then the need date for additional supply capability will be sooner. The supply security need, as discussed, is today. Therefore, additional supply should be implemented as soon as practical. Based on the lead-time required to develop major supply options, the earliest in-service date is estimated to be the end of 2011.

6.0 ALTERNATIVE ANALYSIS

6.1 Alternative #1: Local Generation

This option would involve a simple-cycle gas generation plant in NYR. This facility would need to provide approximately 150 MW of firm capacity, with an overall size of roughly 350 MW.

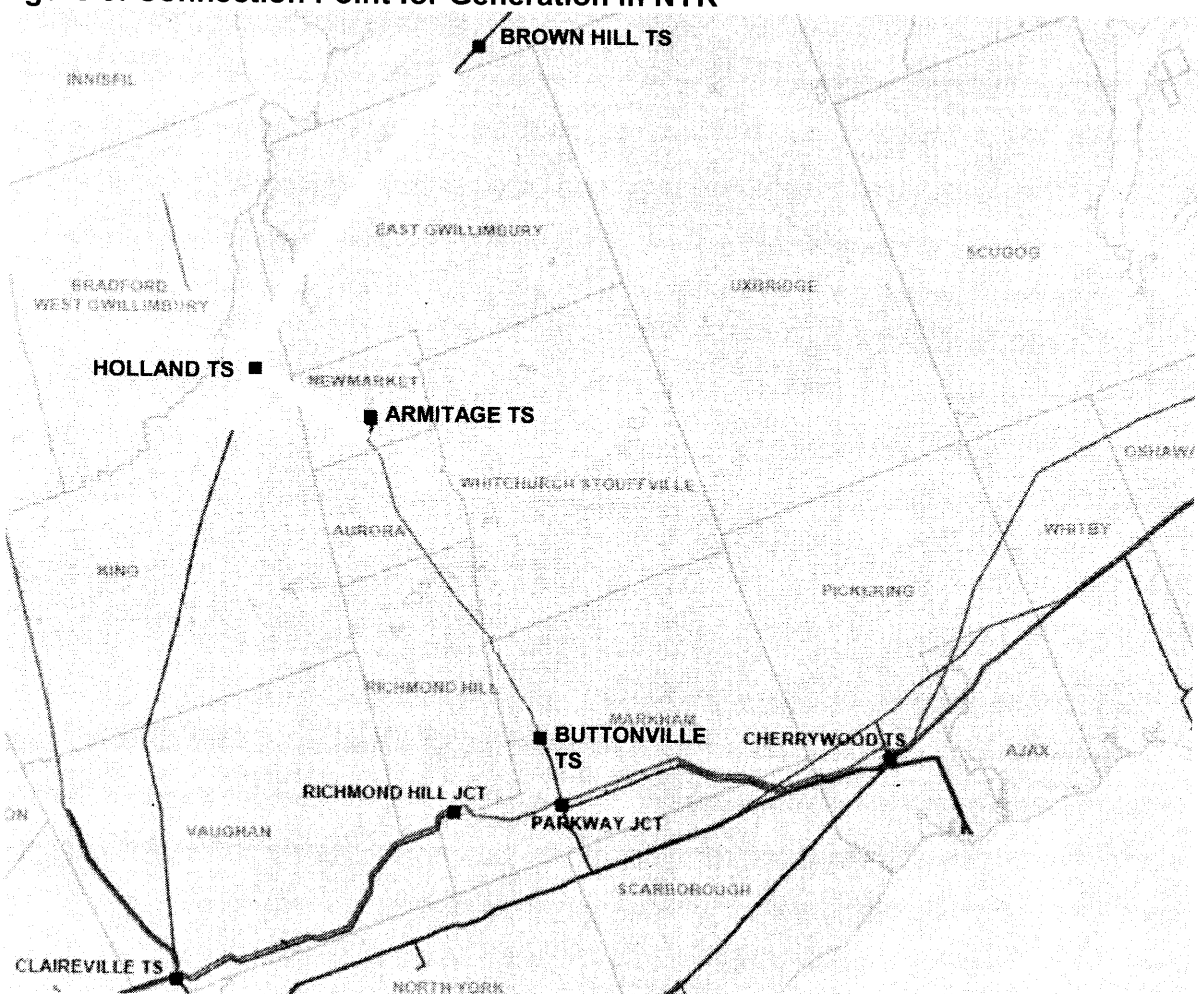
The firm capacity is determined by the loss of one of the 230 kV supply circuits, B82V or B83V to the area. For this contingency, approximately 420 MW can be supplied in NYR after the addition of Holland Junction TS, according to the IESO's Holland Junction TS SIA, in Attachment 1 to this exhibit. The maximum area demand that can be supplied in this area is roughly 600 MW (i.e., four step-down transformer stations) and so the generator would need to be able to provide roughly 150 MW of firm capacity (i.e., with one generating unit out of service) in conjunction with other Conservation and distributed generation measures to meet future adequacy needs.

The overall size of the generation plant is determined by an [N-2] contingency, or the loss of the 230 kV line from Claireville. The Brown Hill end of the line can supply approximately 150 MW of load to NYR following this contingency. After deducting the existing Keele Valley generation (19 MW), expected future distributed generation (21 MW) and load transfers in the distribution system, approximately 350 MW of supply is required to be provided by local generation.

Beyond the benefits for loads in NYR, local generation in NYR will also relieve loading demand on the 500/230 kV autotransformers at Claireville and reduce system losses.

The generation facility for NYR would need to be a transmission connected, peaking gas generator in order to satisfy both system and local needs. This facility could be connected anywhere on the Armitage tap, up to 5 km south of Holland Junction, and up to the East Gwillimbury boundary to the north, as shown in the diagram in Figure 3.

Figure 3: Connection Point for Generation in NYR



Source: OPA, Hydro One

The closer the generator is to Armitage TS, the lower the risk of an outage necessitating load curtailment. Ideally, the generator would be connected to Armitage so that if a line outage ([N-2] contingency) was suffered anywhere on the Claireville to Brown Hill line or the Armitage tap, the area would still have sufficient supply capacity. As the distance from Armitage increases, the risk of exposure to a contingency also increases. Locating generation within the identified boundaries will minimize this risk to the extent possible while permitting more options for siting of the generating plant.

The in-service date of the end of 2011 can be met if some of the preliminary work is initiated now and the formal procurement process is initiated at latest in 2008.

While the generating plant will be acquired through an appropriate procurement process, based on typical costs for a generic gas-fired peaking plant, the capital cost for this option, assuming a 350 MW size plant, is estimated to be about $200 million.

6.2 Alternative #2: Transmission and Generation Elsewhere in Ontario

This option would involve a new transmission line serving the area and an equivalent sized gas-fired generating plant located elsewhere in Ontario. The transmission component of this option proposes the replacement of the existing 115 kV line from Buttonville TS to Armitage TS, a distance of 22 km, with a new double-circuit 230 kV line. This new line will require both a Class EA and an OEB Section 92 leave-to-construct approval. The estimated capital cost of this transmission line, assuming overhead line construction, is $60 million. There was significant community opposition to this option, including the view that if the line was built, it should be buried, at least through urban areas. Undergrounding half of this line would significantly increase the capital costs, to an estimated $110 million. The capital cost of the generation component of this option would be similar to the local generation option.

Other transmission options were examined by the OPA and the community working group in the summer of 2005. None exhibited any overall advantage in terms of cost and impact over the Buttonville to Armitage option.

Assuming a roughly three year lead time is required for approval and construction, the end of 2011 in-service could be met if the development process commenced in 2008.

7.0 ALTERNATIVE COMPARISON

In planning a preferred alternative to meet the needs in NYR, the OPA assessed the alternatives with respect to feasibility, reliability, cost, flexibility, environmental performance and community acceptance. While largely aimed at addressing NYR's local reliability needs, the OPA also took into consideration aspects of the Directive, in particular, respecting natural gas-fired generation and coal-fired generation replacement.

7.1.1 Feasibility

Both generation and transmission alternatives are feasible for NYR. They use well-known technologies that have been implemented in Ontario. Both alternatives are capable of meeting the necessary timeline, although community opposition to the transmission option increases the risk of this option being delayed beyond the need date.

7.1.2 Reliability

Both generation and transmission alternatives address reliability needs in NYR – both options provide supply capability and meet applicable reliability standards and criteria.

7.1.3 Costs

Both the transmission and generation alternatives address the needs in NYR. However, in either case, new generation will be required in Ontario to meet the Directive's gas objectives and system needs. This being the case, the OPA began its analysis by (i) considering whether NYR was an appropriate location to site gas-fired generation for system needs, and if so (ii) how the cost of locating gas generation in NYR compared to the cost of locating gas near Sarnia or converting some of the Nanticoke units plus implementing the local transmission option.

A financial analysis was performed to compare the difference in cost between pursuing the generation alternative in NYR and the transmission alternative in NYR, in combination with system generation elsewhere. Two alternative locations for system generation were examined: the Dawn Hub (the location in Ontario with the lowest commodity and gas transportation cost) and Nanticoke (the location in Ontario with the lowest plant capital costs due to conversion of the existing coal units to gas generation). The goal of the analysis performed was to determine whether the incremental cost of providing generation locally was cost effective. See Exhibit E-2-5 for a description of the methodology for evaluating and comparing these alternatives. The specific cost assumptions used for analyzing these alternatives are summarized in Table 6. The cost assumptions are net-present values, listed in 2007 dollars.

Table 6: NYR Gas Analysis Costs and Results

	Nanticoke		Dawn		York	
Plant Size (MW)		**500**		**350**		**350**
Capital Cost ($M)	$	65.4	$	192.3	$	195.4
Gas Infrastructure: Up-Front Cost ($M)	$	131.7	$	14.0	$	8.3
Gas Tariffs ($M)	$	109.7	$	48.1	$	79.9
Fuel Cost ($M)	$	121.9	$	110.2	$	110.2
Fixed OM&A ($M)	$	143.9	$	67.2	$	67.2
Variable OM&A ($M)	$	6.3	$	3.9	$	3.9
SUB-TOTAL ($M)	**$**	**578.8**	**$**	**435.5**	**$**	**464.8**
Transmission Costs - Overhead (O/H) ($M)	$	59.5	$	59.5	$	-
Transmission Costs - Partially Underground (U/G) ($M)	$	109.1	$	109.1	$	-
TOTAL - with O/H Transmission ($M)	**$**	**638.3**	**$**	**495.0**	**$**	**464.8**
TOTAL - with Partially U/G Transmission ($M)	**$**	**687.9**	**$**	**544.6**	**$**	**464.8**

Source: OPA

Local Gas versus Generation at the Dawn Hub —The cost of generation is essentially common between these alternatives – the only additional costs are reflected in gas infrastructure charges and costs for transportation and storage of gas. The choice of location in NYR can change the up-front capital required for gas infrastructure as well as the annual tariff charges. Therefore, an average of the highest and lowest cost plant locations in NYR was examined in this analysis. The overall results show that generation located in NYR is more cost effective than locating the same generation at the Dawn Hub and building new transmission to serve the demand growth in NYR. As shown in Table 6, the local generation alternative was more economic by roughly $30 million assuming overhead transmission in NYR for the alternative with system generation at the Dawn Hub. The cost difference between the two alternatives will increase further if undergrounding is required. If partial underground transmission is assumed for the Dawn Hub alternative, the cost difference will increase to close to $80 million.

Local Gas versus Nanticoke Conversion —The next analysis compared local generation in NYR to generation at Nanticoke. The analysis compared converting one unit at Nanticoke to 350 MW of local generation in NYR. The Nanticoke units are 500 MW in size and are not scalable to match the requirements of the local area. The NYR generation was assumed to operate at an average capacity factor of three percent with an equal annual energy output assumed from the converted Nanticoke units. Again, an average of the highest and lowest cost plant locations was assumed in NYR. The cost analysis model indicated that the local generation alternative was lower in cost by about $174 million, assuming overhead transmission in NYR for the Nanticoke alternative. The cost difference between the two alternatives would increase to approximately $223 million if the transmission project requires even partial undergrounding. Table 6 summarizes this comparison.

The OPA concluded that in both cases, the local generation alternative was the most cost effective.

7.1.4 Flexibility

Both generation and transmission resources are large lumpy capital expenditures. There is little capability to stage their development. However, generation in NYR will function as a system resource, as it is required by the system regardless of the NYR supply capacity requirements. Therefore, pursuing local generation in the near-term leaves the option for additional supply capacity to be provided by the transmission alternative over the longer-term. Should the area demand growth exceed the capacity of the local generation in the future, the transmission alternative can always be implemented to provide additional supply. Therefore, the local generation alternative is superior from a flexibility perspective.

7.1.5 Environmental Performance

The system requires gas-fired generation and if gas-fired generation is not built in NYR then it would have to be built elsewhere. The environmental impact of gas-fired generation – greenhouse gas emissions and water use – are relatively equivalent across Ontario. The NYR local generation alternative is preferable to the system generation plus transmission alternative since it is less impactive from a land use requirement perspective.

7.1.6 Societal Acceptance

In considering the needs and potential solutions for NYR, there was a significant level of community involvement and input over the course of the study. The OPA engaged the affected communities and local utilities in the process by soliciting and receiving advice, feedback, and comment with respect to the identification, definition and evaluation of electricity supply and Conservation options. The OPA met with key staff and elected officials; organized three large public meetings; formed a working group of municipal government staff, residents, school board representatives, business community representatives, and public interest group representatives; developed a project website; and invited the general public to all working group sessions and elected officials meetings, as observers.

The community, through the stakeholder consultation process, expressed considerable concern about the transmission alternative. Concerns generally focused on the impact on property values, electromagnetic fields and aesthetics. However, in terms of job creation, and future economic and regional development, generation and transmission were found to be equivalent.

The overall preference heard through the stakeholder consultation process was for a local generation solution.

7.1.7 Choice of Alternative

Local gas-fired generation was the preferred alternative based on feasibility and cost, as shown in Table 7. It also has greater societal acceptance, better environmental performance, and more flexibility.

Table 7: Alternative Comparison

	Feasibility	Reliability	Economics	Flexibility	Environmental Performance	Societal Acceptance
Alternative 1 - Generation	Better	Equivalent	Better	Better	Better	Better
Alternative 2 - Transmission	Less Favourable	Equivalent	Less Favourable	Less Favourable	Less Favourable	Less Favourable

Source: OPA

However, acquiring a major generating resource through a procurement process is never certain either in terms of cost or the success of the proponent in siting and obtaining regulatory approvals. Thus, the OPA considers it prudent to maintain the transmission option as a back-up plan. Should the generation option experience setbacks or not reach a successful outcome, the OPA will take the necessary steps to initiate project development work on the transmission option.

8.0 RECOMMENDATIONS AND PROJECT TIMELINE

8.1 Recommendation

After evaluating the alternatives for meeting the needs in NYR, the OPA recommends that the supply need in NYR be addressed by providing local generation with transmission as a back-up. Accordingly:

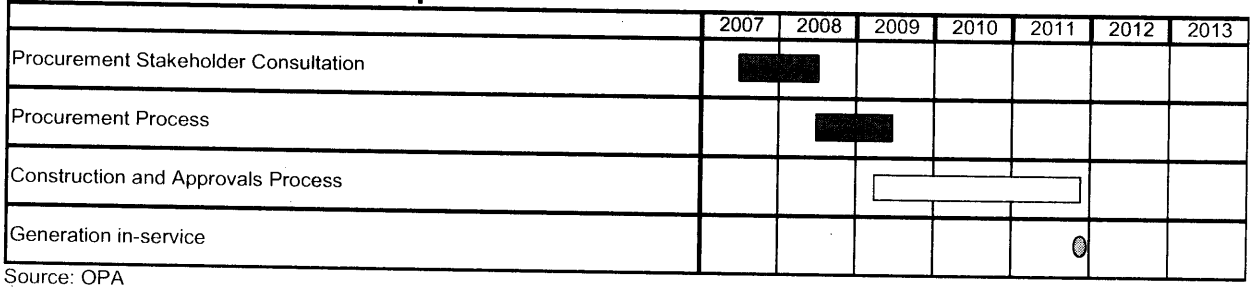
- The OPA intends to procure approximately 350 MW of gas-fired peaking generation in Northern York Region;
- In the event the procurement process is delayed or in the OPA's view is unlikely to lead to the desired outcome, the OPA will take steps to immediately initiate the necessary Transmission Development Work (defined below). The estimated cost for the Transmission Development Work is about $2 million, or about 2% of the total project cost.

8.2 Timeline

Figure 4 illustrates the estimated timeline for implementation of local generation:

Figure 4: Local Generation Option Estimated Project Timeline

NYR - Local Generation Option

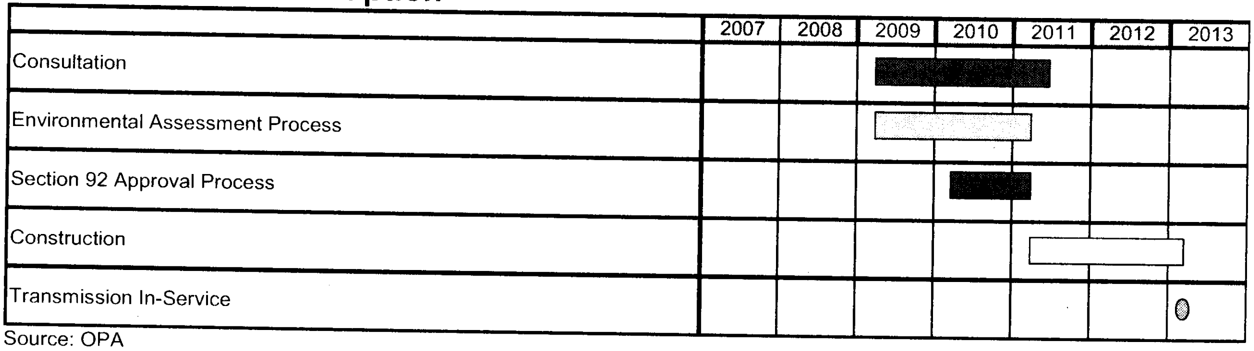


Source: OPA

If the back-up transmission option were to proceed in 2009, then the estimated timeline in Figure 5 may be followed. Development work encompasses all items up to the construction of the facilities.

Figure 5: Transmission Option Estimated Project Timeline

NYR - Transmission Option



Source: OPA

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REPORT

System Impact Assessment Report

CONNECTION ASSESSMENT & APPROVAL PROCESS

Issue 1.0

FINAL Draft REPORT

Project: Holland TS
Applicant: Hydro One Networks Inc.

CAA ID 2006-211 Phase II

Transmission Assessments & Performance Department

February 14, 2007

Document ID	IESO_REP_0341
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System Impact Assessment Report

Holland 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 connection applicant and the transmitter(s) 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(s) 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(s) 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 it is using the most recent version of this report.

HYDRO ONE

Special Notes and Limitations of Study Results

The results reported in this study are based on the information available to Hydro One, at the time of the study, suitable for a preliminary assessment of a new generation or load connection proposal.

The short circuit and thermal loading levels have been computed based on the information available at the time of the study. These levels may be higher or lower if the connection information changes as a result of, but not limited to, subsequent design modifications or when more accurate test measurement data is available.

This study does not assess the short circuit or thermal loading impact of the proposed connection on facilities owned by other load and generation (including OPGI) customers.

In this study, short circuit adequacy is assessed only for Hydro One breakers and does not include other Hydro One facilities. The short circuit results are only for the purpose of assessing the capabilities of existing Hydro One breakers and identifying upgrades required to incorporate the proposed connection. These results should not be used in the design and engineering of new facilities for the proposed connection. The necessary data will be provided by Hydro One and discussed with the connection proponent upon request.

The ampacity ratings of Hydro One facilities are established based on assumptions used in Hydro One for power system planning studies. The actual ampacity ratings during operations may be determined in real-time and are based on actual system conditions, including ambient temperature, wind speed and facility loading, and may be higher or lower than those stated in this study.

The additional facilities or upgrades which are required to incorporate the proposed connection have been identified to the extent permitted by a preliminary assessment under the current IESO Connection Assessment and Approval process. Additional facility studies may be necessary to confirm constructability and the time required for construction. Further studies at more advanced stages of the project development may identify additional facilities that need to be provided or that require upgrading.

System Impact Assessment Report

SIA Findings

SIA Conclusions

This System Impact Assessment has examined the benefits and impact of new transformer station in the New Market area on the reliability of the IESO-Controlled grid. The installation of the new station is a development project that will relieve current station overloads and provide the adequate level of supply to the area loads. The need for this development was originally identified by Hydro One in a study that was jointly performed with the local utilities. The need for the new DESN was reconfirmed in the OPA in the York Region Supply Study together with other development plans which provide solutions in the long term.

Study Conclusions

The studies concluded that:

1. The proposed project will not have a material adverse effect on the reliability of the IESO-Controlled grid.
2. The proposed project will relieve the transformer station over-loadings currently occurring in York Region at Armitage MTS#1 and #2.
3. The addition of the new station will result in a small increase in short circuit currents due to the grounding of the transformers but there is no material increase in the short circuit fault levels.
4. The thermal capability of the double circuit line B82V & B83V, which is restricted by the Woodbridge JCT to Holland Marsh JCT section of the line, is expected to be adequate beyond 2014 assuming that local and system generation is available during peak load conditions.
5. Post-contingency voltage decline on the Holland TS 44 kV bus, prior to transformer ULTCs response, will be within the 10% decline criterion for the new station loading within its LTR.
6. The transmission capability of B82V/B83V circuits is currently limited to about 375 MW due to voltage collapse considerations. This problem will diminish with the incorporation of the new station.
7. An escalation of Holland TS load would result in decay of Armitage TS 230 kV voltage. The IESO's minimal pre-contingency voltage limit of 220 kV will be exceeded for the Holland load greater than 154 MW (2013).

Notification of Approval for Connection Proposal

It is recommended that a Notification of Conditional Approval for connection be issued to Hydro One, subject to IESO's Requirements for Connection listed below, and any further requirements that may be identified by Hydro One Networks Inc. in the Customer Impact Assessment.

IESO's Requirements for Holland TS Connection

The IESO requirements for the connection of the proposed Holland TS are as follows:

- The connection applicant must ensure that load power factor, when measured at the defined meter point location meets the Market Rules requirements.
- Hydro One is required to confirm that UFLS will be installed at the station to meet the Market Rules requirements.
- Hydro One must provide 3% or 5% voltage reduction capability that can be implemented in five minutes.
- Hydro One must install all the equipment needed to monitor the information required by the IESO on a continuous basis.
- All high voltage equipment must be capable of operating continuously with a system voltage as high as 250 kV.
- All equipment must be capable of operating during the re-preparation period with a system voltage as high as 260 kV.
- Hydro One is required to implement a plan for the above identified issues.

IESO's Recommendations for Holland TS Connection

- It is recommended that Hydro One replace the Claireville - Minden Overload Protection Scheme (VMOPS) with a load shedding scheme to mitigate the severity of load disruptions following contingencies.
- The IESO concurs with the findings of the OPA's York Region study and recommends that a new transmission line be built into the area and/or local generation be installed and connected to 230kV system in York Region to solve the identified problems, by 2011.

Table of Contents

1. Project Description

Hydro One Networks is proposing to construct a DESN, Holland TS, located in the vicinity of Holland Marsh Junction. The proposed Holland TS will relieve the Armitage TSs No. 1 & No. 2 as well as provide additional capacity to accommodate future load growth in the local areas supplied by Newmarket Hydro, Aurora Hydro & Hydro One Retail.

The peak summer loads on the two 230/44kV DESN stations at Armitage TS have exceeded the limited-time-ratings of the existing facilities. Summer 2005 peak load at Armitage TS was 366 MW, about 13.4% above the planning limit of 317 MW. Load growth in the area is averaging about 3% per year. The OPA, in their "Northern York Region Electricity Supply Study" dated September 30, 2005 (Section 6.2 – Phase 1 – York Region) recommended the following projects to develop a solution to address the ongoing load growth:

1. Increase the amount of static capacitors at Armitage TS by the summer of 2006.

2. Establish a new 215.5/44 kV, 75/125 MVA DESN station at Holland Junction, along with static capacitors at this station.

Hydro One has requested the IESO to proceed with a CAA study for the new Holland TS and the replacement of capacitor banks at Armitage TS. The replacement of capacitors at Armitage TS was assessed (CAA ID 2006-211) as Phase I of this CAA study and a NOA was granted to Hydro One in June 2006.

The proposed Holland TS is scheduled for completion by summer 2007 and the in-service for the proposed larger capacitor banks is targeted by summer of 2006.

This connection assessment study will examine the proposed connection arrangement for the new facilities and their impact on reliability of the IESO-controlled grid.

– End of Section –

2. Review of Connection Proposal

2.1 Connection Arrangement

The proposed Holland TS will be a 75/125 MVA, 215.5/44 kV DESN that is to be connected to the 230 kV Claireville TS to Brown Hill TS circuits, B82V and B83V. Location of tap for the preferred station site is just over 1/2 km from Holland Marsh Jct on the Claireville TS side. The tap length itself is about 350 meters.

The existing transmission configuration as well as the location of proposed Holland TS is shown in Figure 1.

The proposed Holland TS will be equipped with two new 215.5/44 kV dual winding transformers. Each transformer will be connected to the IESO-controlled grid via one 230 kV motorized disconnect switch. The transformers are both identical and configured with a wye winding on the high side (neutral grounded) and wye (neutral grounded via a 5 ohms reactor) winding on the low voltage side. Each transformer is equipped with under-load tap changer located on the high voltage winding with a range of about ±40 kV that is to be achieved in 32 steps. The transformer impedance is 13% based on 75 MVA.

Two low-voltage shunt capacitor banks (2×32.4 MVAr rated at 46 kV) with associated breakers, surge arresters and reactors will be installed at the proposed Holland TS. One capacitor bank is to be connected to each 44 kV bus.

Low voltage side isolation of each transformer is to be provided by a 2500 A, 44 kV circuit breakers. The LV bus-tie breaker, rated for 2000 A, is to be operated normally closed. The station will have eight feeders and each feeder position is to be equipped with one 1200 A breaker as the same as the capacitor breakers. The short circuit interrupting capability for all above breakers is 20 kA.

The 350 m 230 kV line taps are to meet the following requirements:

- Nominal system voltage 230 kV
- Maximum continuous operating voltage 250 kV
- Ampacity (Continuous) 500 A
- 1 hour emergency 630 A
- Short circuit capacity (ultimate) 63 kA

The points of connection or defined meter points will be located on the high voltage side of the transformer. The exact location of the revenue meter has to be provided by the connection applicant as part of the Facility Registration process.

Proposed Holland DESN single line diagram is shown in Figure 2.

2.2 Power Factor

The Market Rules (Appendix 4.3) require that wholesale customers and distributors connected to the IESO-controlled grid shall operate at a power factor within the range 90% lagging to 90% leading as measured at the defined meter point. Hydro One did not provide load information for Holland TS but proposed to install two 32.4 MVAr capacitor banks at the new DESN to provide load power factor correction.

The connection applicant must ensure that load power factor, when measured at the defined meter point location meets the Market Rules requirements.

2.3 Underfrequency Load Shedding Requirements

The Market Rules (Chapter 5 section 10.4) require that each distributor and connected wholesale customer, in conjunction with the relevant transmitter, make arrangements to enable the automatic disconnection of up to 35% of its peak demand for conditions of system under-frequency. To meet this requirement an under frequency load shedding (UFLS) scheme must be installed at the station. The single line diagram does not show the presence of the UFLS scheme.

The under frequency automatic load shedding should be provided by tripping 44 kV feeder breakers to achieve:

- Automatic load shedding of 12% of station load at a nominal set point of 59.3 Hz and
- Automatic load shedding of an additional 23% of station load at a nominal set point of 58.8 Hz, for a total load reduction of 35% of the total station load.

The under frequency threshold relays shall be set to a nominal operating time of 0.30 second, from the time when frequency passes through the set point to the time of circuit breaker trip initiation (including any communications time delay), when the rate of frequency decay is 0.2 Hertz per second.

Hydro One will identify the UFLS feeder selection closer to the commissioning date and review the selection through the initial loading stages.

Hydro One is required to commit that UFLS facilities will be installed at the station to meet the Market Rules requirements.

2.4 Voltage Reduction Facilities Requirements

The Market Rules (Chapter 4 Appendix 4.3) require that distributors connected to the IESO controlled grid with directly connected load facilities of aggregated rating of 20 MVA or more and the capability to regulate distribution voltage under load, shall install and maintain facilities to provide voltage reduction capability to achieve load reduction during periods when supply resources are limited. Voltage reduction capability represents the capability of reducing demand by lowering the customer voltage by 3% and 5% and having the controlling authority to be able to effect the voltage reduction within five minutes of receipt of the direction from the IESO.

Hydro One is required to commit to install voltage reduction capability that provides 3% and 5% voltage reduction within five minutes.

2.5 On-line Monitoring

The Market Rules (Chapter 4 section 7.4) require that each transmitter shall provide the IESO on a continual basis with on-line monitored quantities as specified in Appendix 4.16. Hydro One must install all the equipment needed to monitor the information required by the IESO on a continuous basis.

The IESO requires that the following quantities at Holland be provided to the IESO on a continual basis via approved communication protocols:

1. The voltage on the high/low tension buses
2. The status of the bus tie breaker
3. The status of the transformer low voltage breakers
4. The status of the capacitor breakers
5. The status of the transformer high voltage disconnect switches
6. The real and reactive power flow through both transformers
7. The transformer tap position for both transformers

2.6 Protection Systems

With respect to the protection and telecommunication requirements, the connection applicant must follow the Transmission System Code technical requirements for tapped transformer stations supplying load.

The applicant has indicated that the station equipment and station control/protection were designed to meet the intent of the Transmission System Code. The diagram that was provided by the applicant shows each transformer being separated from the transmission system via a motorized disconnection switch. For this particular arrangement the Transmission System Code requires that the distributor send transfer trip to the Transmitter's breakers at the line terminal stations for transformer faults or for a condition of failure to operate of the LV transformer breakers.

The protection systems associated with B82V/B83V are to be revised as required.

– End of Section –

3. Data Verification

The proposed new Holland TS will be a standard DESN arrangement with two 75/100/125 MVA transformers. Based on standards for supply of municipal electrical utilities the capability of a DESN station is defined as the maximum load that one transformer can carry for a predefined period of time. This value is usually computed using specific transformer data and daily load curves, and temperature data specific to the transformer location. Hydro One has provided a 10 day summer Limited Time Rating of 170 MVA.

The high voltage motorized disconnect switches are designed to meet the requirements as specifies for 230 kV line taps with maximum continuous operating voltage of 250 kV. The applicant has advised that each disconnect switch shall be rated to interrupt the maximum magnetizing current of the specified 75/100/125 MVA transformer.

The system performance standards listed in the Transmission System Code requires that the 44 kV system fault level not exceed 20 kA. This indicates that 44 kV equipments must be sized to interrupt 20 kA. The LV breakers proposed for installation at Holland TS meet the interrupting capability recommended by the Transmission System Code.

A full description of the connection arrangement of the proposed Holland TS is included in Section 2.1 of this report.

– End of Section –

4. Fault Level Assessment

The customer has advised that there is no generation or large synchronous motors connected to their distribution system.

In general, radial loads do not have a large impact on the system fault levels, but a small contribution in short circuit currents can be observed due to the grounding of the transformers. In the case of Holland TS the high voltage winding is ungrounded, hence line-to-ground faults occurring on the distribution side will have no impact on the short circuit levels.

– End of Section –

5. Impact on System Reliability

This connection assessment study concentrated on identifying the effect of the proposed DESN on thermal loading of the transmission lines and transformers, voltage stability, voltage changes for capacitor switching and system voltages for pre and post contingencies.

5.1 Study Assumptions

For this connection assessment the July 2006 base case was used with the following assumptions:

1. New 4 × 32.4 MVAr at Armitage TS
2. Keele Valley GS I/S with two generating scenarios:
    - GS power output of 30 MW (maximum power output)
    - GS power output of 22 MW (power output during summer peak day of August 1)
3. Des Joachims I/S and O/S
4. Load power factor of 0.87 was assumed
5. Constant MVA load model was used for voltage stability studies while voltage decline and thermal assessment studies were done with load modeled as voltage-dependant (50% constant impedance and 50% constant current for active power and 100% constant impedance for reactive power).

5.2 Load Forecasts and Load Supply Deliverability

In 2003 Hydro One and York Region utilities performed a study (York Region Supply Study: Adequacy of Transmission Facilities And Transmission Supply Plan 2003-2013) to review the area load growth in York Region and the adequacy of the existing transmission system to supply the demand for the next ten years. The study concluded that the load in the York Region was expected to increase at a rate of about 4.0% annually to 2008 and the long term growth rate from 2008 to 2013 was about 3.4%.

Based on the York Region Supply Study and the load growth rates provided by Hydro One, the load growth rates and the load forecasting for the stations supplied by B82V/B83V and M80B/M81B are summarized in Table 1 and Table 2, respectively. Since the load at Armitage TS in 2005 has already exceeded its load meeting capabilities, load at this station is limited to station capability (317 MW). The Armitage TS load in excess of 317 MW and the load growth based on 366.5 MVA by 3.25% per year will be included in the load forecast for the new Holland TS.

Table 1: Load Growth Rate

Station	Summer Peak for 2005 (MW)	Load Growth Rate (%)
Armitage	366.5	3.25
Brown Hill TS	68.9	0.75
Beaverton TS	60.4	1.55
Lindsay TS	70.5	0.45

Table 2: Load Forecast (MW)

Station	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Armitage	366.5	378.4	317	317	317	317	317	317	317	317	317	317	317
Holland	0	0	73.7	86.4	99.5	113.1	127.0	141.5	156.4	171.8	187.6	204.0	221.0
Brown Hill	68.9	69.4	69.9	70.4	70.9	71.5	72.0	72.6	73.1	73.6	74.2	74.8	75.3
Beaverton	60.4	61.3	62.3	63.2	64.2	65.2	66.2	67.3	68.3	69.4	70.4	71.5	72.6
Lindsay	70.5	70.9	71.2	71.5	71.8	72.1	72.5	72.8	73.1	73.4	73.8	74.1	74.4

Load forecast for the Armitage & Holland stations supplied by B82V and B83V will be used with the simulation results to determine the year when constrains will occur.

The load security and restoration criteria for IESO-controlled grid are defined in the Ontario Resource and Transmission Assessment Criteria document as follows:

"With any one element out of service, equipment loading must be within applicable long-term emergency ratings, voltages must be within applicable emergency ranges, and transfers must be within applicable normal condition stability limits. Not more than 150MW of load may be interrupted by configuration. Planned load curtailment or load rejection, excluding voluntary demand management, is not permissible.

With any two elements out of service voltages must be within applicable emergency ranges. Equipment may be loaded up to applicable short-term emergency ratings immediately following a contingency, but must be reduced to the long-term emergency ratings in the time afforded by the short-term ratings. Not more than 600MW of load may be interrupted as a result of the contingency, and this may include up to 150MW of planned load curtailment or load rejection, excluding voluntary demand management.

The transmission system must be planned such that, following design criteria contingencies on the transmission system, affected loads can be restored within the restoration times listed below:

All load must be restored within approximately 8 hours.

When the amount of load interrupted is greater than 150MW, the amount of load in excess of 150MW must be restored within approximately 4 hours.

When the amount of load interrupted is greater than 250MW, the amount of load in excess of 250MW must be restored within 30 minutes."

It should be noted that based on the load forecasts in Table 2 the load supplied exclusively by the 230 kV circuits B82V & B83V and M80B & M81B which include load at Armitage TS, Holland TS Brown Hill TS Beaverton TS and Lindsay TS, is above 600 MW guideline level starting in 2008. For the permanent loss of either the north or south section of the Claireville to Minden line, rapid isolation of the faulted section and restoration of the supply to some of the loads ca be achieved by the operation of the Brown Hill in-line breakers. However, the permanent loss of B82V/B83V will result in the loss of more than 250 MW without the ability of restoring the load in excess of 250 MW in 30 minutes, which exceeds the above mentioned criteria.

5.3 Thermal Loading Assessment

This section covers an investigation of thermal loading capability of 230 kV circuits supplying the new project.

A power flow analysis was performed under summer peak load conditions for all elements in service and for single element contingencies. Two generation scenarios were considered, with all eight units at Des Joachims GS in service and out of service.

Increasing output at Des Joachims GS will increase flows on M80B & M81B and will decrease flows on B82V & B83V circuits and vice versa.

The ratings used to evaluate the thermal capability of the Claireville TS to Minden TS 230 kV transmission corridor are shown in Appendix A. The table lists the continuous ratings and the 15 minute limited time ratings of all the line sections. For these circuits it was assumed that the long term emergency rating is the same as the continuous rating. As it appears from the listed ratings, there are four sections of circuits B82V & B83V. The circuit section (2) from Woodbridge JCT to Holland Marsh JCT has the lowest rating and therefore is the most limiting section. The most limiting section for the M80B & M81B circuits is section (9) from Minden TS to Beaverton JCT.

The ratings were calculated for the summer peak conditions, i.e. temperature of 35°C, wind speed of 5 km/h and for the day time. Pre-load dependant LTRs were calculated assuming circuit pre-contingency loading of 75%.

It should be noted that pre-contingency voltages based on historical data were used to convert ampacity to a MVA rating in Appendix A. The pre and post-contingency MVA ratings used in table 3 were calculated using post-contingency voltages.

The criteria applied in assessing the thermal loading capability of the 230 kV circuits is the following:

- With all elements in-service, loading of any line shall be within their continuous rating.
- For the single circuit contingency, post-contingency flow on any circuit shall not exceed the 15 minute limited time rating.

The results of 2014 case studies including pre and post contingency flows are summarized in Table 3.

The study results indicate that:

With all elements in service pre-contingency, the power flows on all transmission circuits are below circuit continuous rating.

When all Des Joachims GS units are in-service, contingencies involving either B82V or B83V circuit would load the remaining circuit above its continuous rating but below its 15-minute LTR. If Des Joachims units are out-of-service, loss of BxV circuit would result in overloading of the companion circuit above circuit's 15-min LTR. In the latter case, load shedding is the only control action available to reduce the loading of the remaining circuit below the continuous rating. Load shedding following a single contingency in this case violates IESO's load supply criteria. However, this problem will be alleviated by the addition of either a new transmission line and/or local generation into the area, as recommended by the OPA in the York Region Supply Study.

The assessment of M80B & M81B circuits' thermal capability indicates that thermal overloading of one of these circuits following the contingency of companion circuit is not a concern.

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Table 3: Pre and Post Contingency Circuit Loadings in 2014

CIRCUIT	LIMITING SECTION	LIMITING SECTION'S CONT & LTR RATING POST-CONT (MVA)	POST-CONTINGENCY FLOWS (MVA)									
			Element Out-of-Service									
			Des Joachims Out-of-Service					Des Joachims In-Service				
			Pre-contingency Flows (MVA) % of Cont Rating	B82V % of Cont Rating	B83V % of Cont Rating	Tap Line #1 % of Cont Rating	Tap Line #2 % of Cont Rating	Pre-contingency Flows (MVA) % of Cont Rating	B82V % of Cont Rating	B83V % of Cont Rating	M80B % of Cont Rating	M81B % of Cont Rating
B82V	WOODBRGJ TO HOLMARSJ	416	236.6 53.3%	0	500.6 120.3% 104.2%*	143.3 34.4%	335.9 80.7%	192.1 43.26%	0	449.2 108%	257.3 61.8%	196.1 47.1%
B83V	WOODBRGJ TO HOLMARSJ	480	240.6 54.2%	505.6 121.5% 105.3%*	0	344 82.7%	148.9 35.8%	196.3 44.2%	455.7 109.8%	0	205.2 49.3%	253.4 60.9%
Tap Line #1		469 539	150.5 30.7%	0	308 65.7%	0	304.6 64.9%	150.6 30.7%	0	308.4 65.7%	137.9 29.4%	160.2 34.1%
Tap Line #2			147.2 30%	307 65.4%	0	306.6 64.5%	0	147.3 30.1%	307.3 65.5%	0	157.1 33.5%	135.7 28.9%
M80B	BEAVERTJ TO MINDEN	309	109.6 33.9%	80.7 26.1%	157.8 51.1%	90.3 29.2%	127.6 41.3%	165.2 51.2%	91.9 29.7%	216.2 69.9%	0	228.3 73.9%
M81B	BEAVERTJ TO MINDEN	396	116.8 36.2%	168.3 54.5%	93.7 30.3%	136 44%	97.7 31.6%	171.8 53.2%	226.3 73.2%	105.4 34.1 %	234.4 75.8%	0

*: % of LTR for post-contingency flow above circuit's 15-min LTR

It is evident that future load growth in the area will aggravate the loading problems of 230 kV B82V & B83V circuits. Table 4 summarizes the dependence of the system capability to supply the yearly peak demand to the availability of the generation. When available to run, the existing local (Keele Valley) and system (Des Joachims) generation will provide a benefit of relieving the loading on the circuits. In the best case scenario which assumes both Keele Valley GS and Des Joachims GS running, the circuit's load meeting capability would be exceeded by summer 2013, as shown in Table 4.

Table 4: Post-contingency Line Loadings

DES JOACHIMS GS & KEELE VALLEY GS OUT-OF-SERVICE				
Year	B83V Out-of-service		B82V Out-of-service	
	Flow on B82V (MVA)	% of Continuous Rating	Flow on B83V (MVA)	% of Continuous Rating
2008	*417*	*95.9 %*	*430*	*98.8 %*
2009	***443***	***104.2 %***	***453***	***106.6 %***
2010	***466***	***109.6 %***	***471***	***110.8 %***
DES JOACHIMS GS OUT-OF-SERVICE & KEELE VALLEY GS IN-SERVICE				
Year	B83V Out-of-service		B82V Out-of-service	
	Flow on B82V (MVA)	% of Continuous Rating	Flow on B83V (MVA)	% of Continuous Rating
2010	*420*	*96.6 %*	*427*	*98.2 %*
2011	***442***	***104 %***	***447***	***105.2 %***
2012	***466***	***109.6 %***	***470***	***110.6 %***
DES JOACHIMS GS IN-SERVICE & KEELE VALLEY GS IN-SERVICE				
2013	*420*	*98.8%*	***428***	***100.7%***
2014	***456***	***109.6%***	***449***	***107.9%***

It is apparent from the study results that if Keele Valley GS is not available for service, the circuit would be loaded to above its continuous rating following the loss of the companion circuit starting in 2009. With Keele Valley in-service and generating 30 MW of power, the occurrence of the circuits post-contingency overloading would be deferred until summer 2011.

However, historical data shows that during the peak day in August Keele Valley power output was about 22 MW. In this case, post-contingency circuit overloading for second and third generating scenarios in the above table would occur in 2010 and 2012 respectively. Keel Valley historical generating data are shown in Appendix B.

5.4 Voltage Profile Assessment

Different system conditions and contingencies were studied to identify the worst case study scenario. The loss of B82V circuit was identified as the most critical single element contingency while the system condition with all Des Joachims generating units out-of-service was found to be the most limiting study condition

It should be noted that voltage assessment study results were based on the initial information provided to the IESO, i.e. Holland TS connected to Armitage TS tap lines, 2 km south of Holland Marsh Junction. The revised Holland TS connection point will result in slightly better voltage performance than that reported so the studies were not repeated.

5.4.1 Voltage Decline Study

The following IESO criteria must be satisfied before any new equipment is connected to the transmission system:

1. The pre-contingency voltage on 230 kV buses can not be less than 220 kV.
2. The post-contingency voltage on 230 kV buses can not be less than 207 kV.
3. The voltage drop following a contingency can not exceed 10% pre-ULTC and 10% post-ULTC.

Power flow studies were performed to assess the pre and post contingency voltages and to identify any voltage requirement violations. With loads modeled as voltage-dependant, the following assumptions were made in determining the voltage decline following the loss of B82V:

- Load at Armitage TS was limited to its LTR of 317 MW.
- Load at Holland TS was escalated to the station LTR of 170 MW.

The study results including pre and post-contingency voltages and voltage changes are summarized in Table 5. The results are given for the scenario 1 e.g. Keele Valley power output of 30 MW.

Table 5: Voltage Change Study Results for Loss of B82V (Year 2014)

ARMITAGE TS & HOLLAND TS LOADED TO 317 MW & 169 MW RESPECTIVELY					
BUS	**PRE-CONTINGENCY (kV)**	**B82V CONTINGENCY**			
		PRE-ULTC (kV)	**VOLTAGE DECLINE (%)**	**POST-ULTC (kV)**	**VOLTAGE DECLINE/RISE (%)**
Holland 230 kV	237.7	226.3	4.78	221.1	6.96
Holland 44 kV	*45.2*	*40.7*	*9.87*	*45.6*	*-0.87*
Armitage 230 kV	236.8	224.3	5.27	218.7	7.63
Armitage 44 kV (1)	45.1	40.9	9.22	45.1	0
Armitage 44 kV (2)	45.1	41.5	7.96	45.4	-0.54
ARMITAGE TS & HOLLAND TS LOADED TO 317 MW & 172 MW RESPECTIVELY					
	PRE-	**B82V CONTINGENCY**			

BUS	CONTINGENCY (kV)	PRE-ULTC (kV)	VOLTAGE DECLINE (%)	POST-ULTC (kV)	VOLTAGE DECLINE/RISE (%)
Holland 230 kV	237.41	225.9	4.85	220.7	7.06
Holland 44 kV	***45.6***	***41.0***	***10.04***	***45.4***	***0.52***
Armitage 230 kV	236.6	223.9	5.34	218.3	7.75
Armitage 44 kV (1)	45.0	40.8	9.32	45.5	-1.05
Armitage 44 kV (2)	45.1	41.4	8.05	45.3	-0.40

The above study results indicate that:

- If loading of Holland TS is below or equal to 169 MW, post-contingency voltage declines on the 230 kV buses before and after ULTCs action, would be within the IESO's criterion of 10%. Immediate post contingency voltage decline on the 44 kV buses, prior to the ULTCs response, would also be within 10 %.
- For the Holland TS load greater than 169 MW, pre-ULTC voltage decline on Holland TS 44 kV bus would exceed 10% limit.

Sensitivity studies showed that there is no significant difference in voltage change when Keele Valley power output was lowered to 22 MW.

5.4.2 Voltage Stability

This study was performed to evaluate the risk of voltage collapse in Armitage area. Figure 3 shows the Holland TS 230 kV and 44 kV bus voltages as a function of the new station loading following the loss of B82V circuit. The curve was generated assuming that Armitage TS load is constant and equal to its LTR (317 MW), and that Keele Valley output is 30 MW.

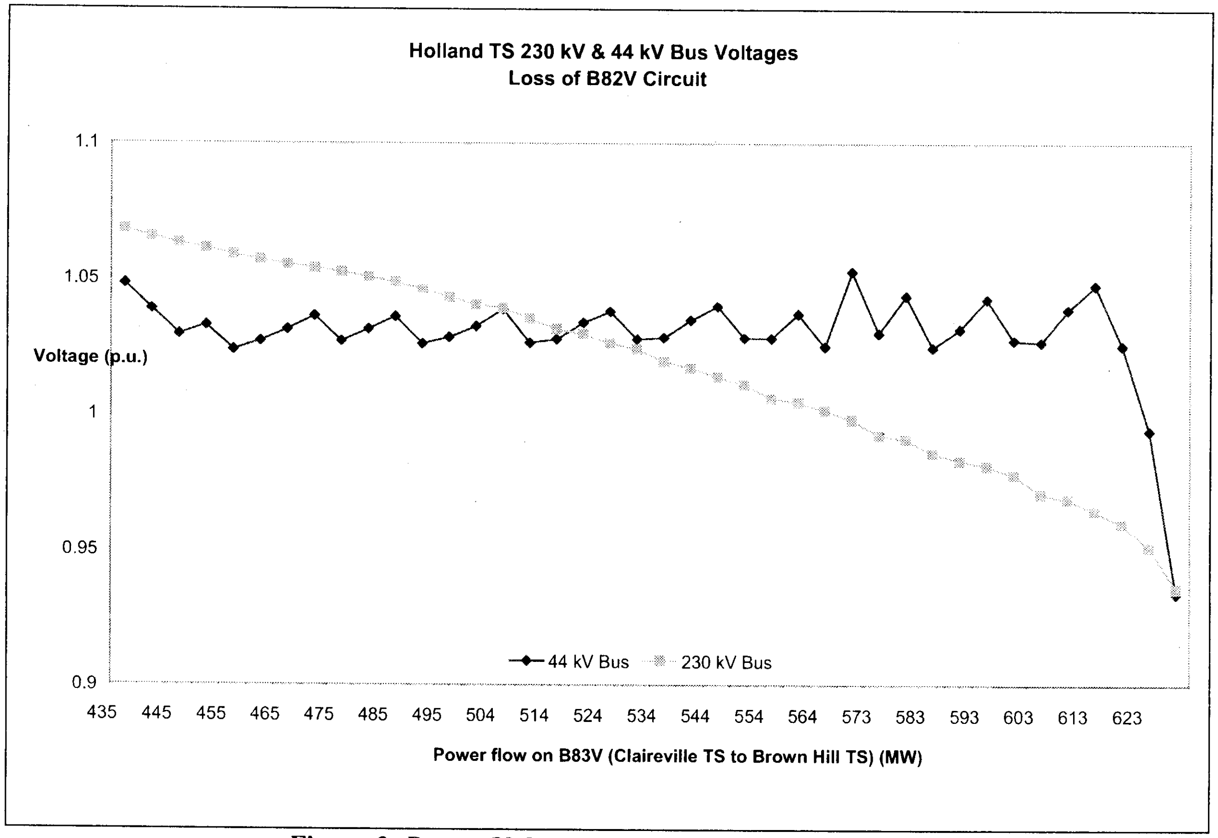


Figure 3: Power-Voltage (P-V) Curve for Holland TS

With the loads modeled as constant MVA, the total peak load that could be supplied by B83V is 626 MW. Allowing a 5% margin gives a load meeting capability of about 595 MW. This would allow Holland TS being to be loaded at 202 MW.

If power output from Keele Valley is 22 MW, load meeting capability of B83V would decrease to 582 MW resulting in Holland TS loading capability being limited to 183 MW. Since load meeting capability exceeds the station design capacity of 170 MW, it can be concluded that transmission capability of B82V & B83V circuits will not be limited by the voltage stability problem.

However, the results summarized in Table 6 indicate that with the escalation of Holland TS load, the 230 kV bus voltages would be approaching the IESO's minimum acceptable voltage limit of 220 kV for all elements in service pre-contingency, or with one element out of service after permissible control actions. For the Keele Valley power output of 30 MW, this limit would be exceeded for the new station loads greater than 159 MW. However, for the power output of 22 MW the limit would be exceeded for the station loading of 154 MW.

Table 6: Pre-contingency and Post-contingency 230 kV Bus Voltages

BUS	INFLOW (MW)	HOLLAND LOAD (MW)	PRE-CONTINGENCY VOLTAGE (KV)	PRE-ULTC VOLTAGE (KV)	POST-ULTC VOLTAGE (KV)
Holland 230 kV	448	159	223.1	222.7	222.4
Armitage 230 kV			220.8	220.4	220.1
Holland 230 kV	452	154	222.6	221.6	221.3
Armitage 230 kV			***220.3***	***219.3***	***218.9***

INFLOW = Post-contingency power flow on B83V into Holland TS & Armitage TS

5.4.3 Capacitor Switching

Two 32.4 MVAr capacitor banks will be installed at Holland TS. This study was performed to examine the effect of capacitor switching on 44 kV bus voltages at Holland TS. As per Chapter 4 of Market Rules, voltage changes shall not normally exceed 4 % of steady state rms for capacitor switching operations.

IESO Transmission Assessment Criteria specifies that voltage-dependant model should be used for capacitor switching studies. However, since the voltage characteristic of the new station load is not available, sensitivity studies were done using both voltage dependant and constant MVA load models. The study results are shown in Table 7.

Results show that the voltage change due to capacitor switching meets the Market Rules criterion.

However, in reality excessive voltage changes could occur if the load at the new station has a constant MVA characteristic.

Table 7: Steady State Voltage Change

LOAD MODEL	VOLTAGE (KV)		VOLTAGE CHANGE	
	Pre-switching	Post-switching	(kV)	(%)
Voltage-dependant (50, 50, 0, 100)	46.28	47.76	1.48	*3.20%*
Constant MVA	46.28	48.41	2.13	***4.60 %***

5.5 Claireville - Minden Overload Protection Scheme

Claireville-Minden Overload Protection Scheme (VMOPS) was installed in 1993 to prevent post-contingency overloads. The scheme was designed to detect loss of B82V or B83V and then trip the in-line breaker of the remaining circuit at Brown Hill with a time delay of 30 seconds. The cross-tripping overload protection scheme is non-duplicated. The scheme has not been used since it was installed. For loss of B82V or B83V, tripping the in-line breaker on the other circuit B83V or B82V would overload it and lead to voltage collapse.

Given the difficulties experienced in the recent past enhancing the system near New Market, there is merit in considering to replace VMOPS with a load shedding scheme to mitigate the severity of load disruptions following contingencies.

5.6 Summary of Findings

Supply conditions in York region are very tight. The triggers and need dates for enhancements to the York Region are summarized in Table 8.

Table 8: Timeline of Supply Constraints to the New Market Area

CONSTRAINTS	HOLLAND LOAD (MW)	YEAR	COMMENTS
SCENARIO 1: KEELE VALLEY OUTPUT 30 MW			
THERMAL Woodbridge JCT to Holland Marsh JCT	99.5	2009	Keele Valley GS out-of-service
	127	2011	KeeleValley GS in-service
PRE-CONTINGENCY VOLTAGE DECLINE	159	2014	Armitage TS 220 kV bus
POST-CONTINGENCY VOLTAGE DECLINE	169	2014	Holland TS 44 kV bus
TRANSFER CAPABILITY	170	2014	Both Holland TS and Armitage TS loaded to stations' LTRs
SCENARIO 2: KEELE VALLEY OUTPUT 22 MW			
THERMAL Woodbridge JCT to Holland Marsh JCT	99.5	2009	Keele Valley GS out-of-service
	113	2010	KeeleValley GS in-service
PRE-CONTINGENCY VOLTAGE DECLINE	154	2013	Armitage TS 220 kV bus
POST-CONTINGENCY VOLTAGE DECLINE	169	2014	Holland TS 44 kV bus
TRANSFER CAPABILITY	170	2014	Both Holland TS and Armitage TS loaded to stations' LTRs

A solution to the above identified issues can be provided by means of either:

- installing local generation connected to 230 kV system or
- building a new transmission line into the area

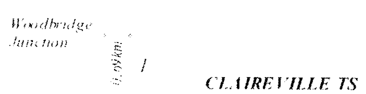
The work is required to be completed before the summer of 2010. This would not only provide the relief to B82V and B83V line but would also improve 230 kV system voltages in the Armitage area and increase the level of security of supply to the area.

Also, new transformation capability would be needed in the area by the summer of 2014 when loading of both Armitage TS and Holland TS is forecasted to reach stations' design capacities.

It is suggested that Hydro One to replace VMOPS with a load shedding scheme to mitigate the severity of load disruptions following contingencies.

– End of Section –

Figure 1 Connection Arrangement of Holland TS



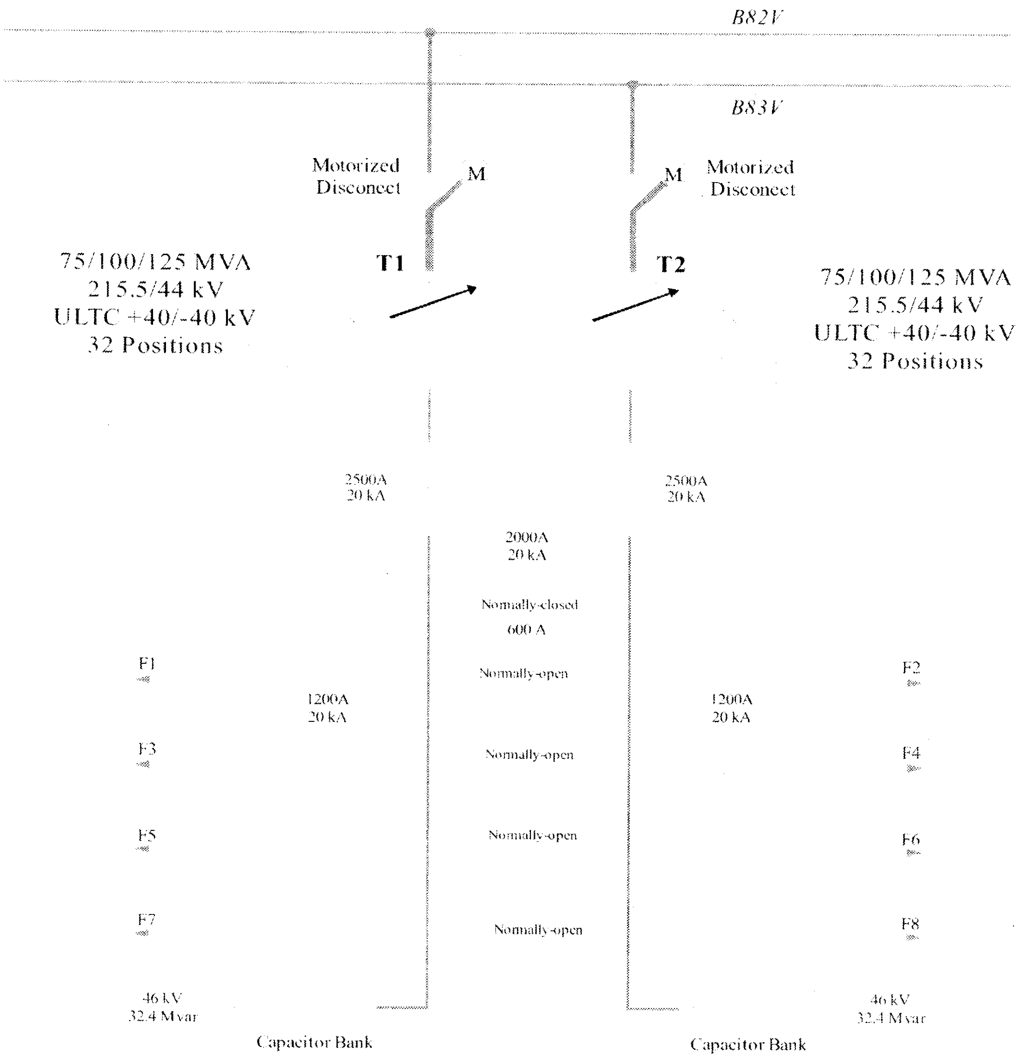


Figure 2. Holland TS Single Line Diagram

Appendix A. Thermal Ratings

230 kV Line Rating: Claireville to Minden							
Ratings at 35℃ Ambient, 5 km/h Wind							
Circuit	*Conductor*		*Max Operating Temperature*	*Continuous Rating*		*15-MIN LTR (Pre-load of 75%)*	
***B82C & B83C: Claireville to Brown Hill TS**, MVA at 235 / 230* kV*							
Claireville to Woodbridge JCT (1)	*1843.2 kcmil*	*72/7*	*127℃*	*1796 A*	*731 MVA*	*2241 A*	*912 MVA*
Woodbridge JCT to Holland Marsh JCT (2)	*795 kcmil*	*26/7*	*127℃*	*1092 A*	*444 MVA*	*1260 A*	*512 MVA*
*Holland Marsh JCT to Armitage TS (3)**	*795 kcmil*	*26/7*	*150℃*	*1230* A*	*490* MVA*	*1414* A*	*563* MVA*
Holland Marsh JCT to Brown Hill TS (4)	*795 kcmil*	*26/7*	*127℃*	*877 A*	*356 MVA*	*998 A*	*406 MVA*
***M80B: Minden to Brown Hill TS**, MVA at 235 kV*							
Minden TS to Beaverton JCT (9)	*795 kcmil*	*26/7*	*104℃*	*793 A*	*322 MVA*	*1017 A*	*413 MVA*
Beaverton JCT to Beaver JCT (7)	*795 kcmil*	*26/7*	*134℃*	*1136 A*	*462 MVA*	*1309 A*	*532 MVA*
Beaver JCT to Beaverton TS (6) *Beaverton JCT to Lindsay TS (8)*	*795 kcmil*	*26/7*	*150℃*	*1230 A*	*500 MVA*	*1414 A*	*575 MVA*
Beaver JCT to Brown Hill TS (5)	*795 kcmil*	*26/7*	*127℃*	*877 A*	*356 MVA*	*998 A*	*406 MVA*
***M81B: Minden to Brown Hill TS**, MVA at 235 kV*							
Minden TS to Beaverton JCT (9)	*795 kcmil*	*26/7*	*104℃*	*793 A*	*322 MVA*	*1017 A*	*413 MVA*
Beaverton JCT to Beaver JCT (7)	*795 kcmil*	*26/7*	*104℃*	*928 A*	*362 MVA*	*1074 A*	*419 MVA*
Beaver JCT to Beaverton T S (6)	*795 kcmil*	*26/7*	*150℃*	*1230 A*	*500 MVA*	*1414 A*	*575 MVA*
Beaverton JCT to Lindsay TS (8)	*795 kcmil*	*26/7*	*127℃*	*1085 A*	*432 MVA*	*1252 A*	*509 MVA*
Beaver JCT to Brown Hill TS (5)	*795 kcmil*	*26/7*	*127℃*	*877 A*	*356 MVA*	*998 A*	*406 MVA*

Appendix B. Keele Valley Power Output