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By E-mail

November 21, 2007

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
P.O. Box 2319, 27th Floor
Toronto, ON M4P 1E4

Dear Ms. Walli:

Re: Ontario Power Generation Inc.
Reliability Must-Run Agreement for 2007-08 for Lennox Generating Station
Board File No. EB-2007-0715

In accordance with Procedural Order No. 1, please find enclosed Board staff's submission with respect to Ontario Power Generation Inc.'s application and evidence.

Yours truly,

Original signed by

Keith C. Ritchie
Project Advisor - Applications

Enclosures

cc: Ontario Power Generation Inc.
Intervenors of Record

Submissions of Board Staff
on the Application by Ontario Power Generation Inc. for Approval of a Reliability Must-run Agreement for the Lennox Generating Station

Board File No.: EB-2007-0715

The following submissions of Board staff are made further to the Board's October 16, 2007 Procedural Order No. 1 in relation to an application by Ontario Power Generation Inc. ("OPG") for approval of a reliability must-run agreement (the "2007-08 RMR Contract") for the Lennox Generating Station ("Lennox").

Board staff's submissions are focused on the issue of the term of future reliability must-run agreements that may be entered into between OPG and the Independent Electricity System Operator (the "IESO") in relation to Lennox.

Introduction

The Ontario Power Authority's (the "OPA") Integrated Power System Plan (the "IPSP") assumes that Lennox will remain in service for local reliability reasons at least through 2010. Attached as Appendix A to these submissions is a copy of the materials filed by the OPA in respect of its application for approval of the IPSP (proceeding EB-2007-0707) that bear on the issue of the need, as part of the Province's electricity generation portfolio, for the continued operation of Lennox. In its November 7, 2007 response to Board staff's interrogatory #3 addressed to the IESO, the IESO confirmed that Lennox is expected to be required for reliability reasons until at least the end of 2009.

In its November 7, 2007 response to Board staff's interrogatory #1 addressed to OPG, OPG indicated that it does not expect that revenues generated from the IESO-administered markets will be sufficient to cover the costs associated with operating Lennox over the period from now to the end of 2010. OPG therefore confirmed that it will be filing a request to de-register Lennox effective October 1, 2008.

Based on the above it appears that, absent a longer term solution, the 2007-08 RMR Contract which is the subject of OPG's application for Board approval in this proceeding will not be the last reliability must-run agreement for Lennox.

Term of Future Reliability Must-run Agreement for Lennox

In its Procedural Order No. 1, the Board contemplated the possibility of requiring that any future reliability must-run agreement for Lennox have a term of more than one year, if that would be more cost-effective. In its November 7, 2007 response to Board staff's interrogatory #3 addressed to the IESO, the IESO confirmed that it has not investigated the merits of a multi-year reliability must-run agreement for Lennox because section 9.7.1.1 of Chapter 7 of the Market Rules restricts the term of reliability must-run agreements to one year or less. The IESO indicated that it had, however, advised the OPA to consider other possible solutions that would eliminate the longer-term requirement for reliability must-run agreements for Lennox.

In its November 14, 2007 written submissions, OPG expressed the view that a multi-year reliability must-run agreement would be more cost-effective, and requested that the Board impose a condition to that effect. OPG also proposed that any future reliability must-run agreement continue to use the existing contract model, regardless of the term of the agreement.

The requirement for Board approval of reliability must-run agreements is a condition of OPG's electricity generation licence (licence no. EG-2003-0104). Specifically, paragraph 5.2 of that licence states in part as follows: "Where an agreement is entered into in accordance with paragraph 5.1,[1] it shall comply with the applicable provisions of the Market Rules or such other conditions as the Board may consider reasonable". The Board has already determined that its

[1] Paragraph 5.1 of the OPG's licence refers to an agreement for the supply of energy or ancillary services that OPG may be required by the IESO to enter into for purposes of maintaining the reliability and security of the IESO-controlled grid.

mandate in reviewing a reliability must-run agreement includes addressing the question of whether the financial provisions of the agreement are reasonable.[2] Board staff submits that, within that framework, a condition requiring that a reliability must-run agreement have a term of greater than one year if that would be more cost-effective would be reasonable. The Board could also achieve the same effect by amending OPG's and/or the IESO's respective licences, if that were considered necessary.

Board staff acknowledges that section 9.7.1.1 of Chapter 7 of the Market Rules stipulates that the term of a reliability must-run agreement cannot exceed one year. However, the Market Rules themselves recognize the authority of the Board to require otherwise. Specifically, section 9.6.11.2 of Chapter 7 of the Market Rules states that the restriction on the term (among other things) of reliability must-run agreements is subject to any contrary provisions contained in "the terms of any *reliability must-run contract* the terms of which are required by a *licence* to be, and have been, approved by the *Ontario Energy Board*".

Board staff currently has no reason to believe that a multi-year reliability must-run agreement for Lennox would not be more cost-effective than a one-year agreement. Similarly, a multi-year agreement may also provide greater incentives to OPG to manage investments in and the operation of Lennox while it is needed as a must-run facility. However, evidence is required to determine whether or not greater cost-effectiveness and/or greater incentives would be the outcome.

Board staff therefore proposes the following approach to the matter:

i. If the Board approves the 2007-08 RMR Agreement, in the Decision approving that Agreement the Board could identify that, for the purposes of paragragh 5.2 of OPG's licence, it will be a condition of any future

[2] This was first articulated by the Board when it considered the first reliability must-run agreement for Lennox in proceeding EB-2005-0490, and was reiterated when the Board considered the second such agreement in proceeding EB-2006-0205.

reliability must-run agreement filed by OPG for approval that the agreement have a term of more than one year if that would be more cost-effective. The appropriate longer term would be determined having regard to the further number of years for which it is reasonably believed that Lennox may be required to continue to operate under must-run conditions, up to a specified maximum term if the Board believes one to be appropriate. As noted above, the OPA currently considers that Lennox may be required for reliability reasons at least through 2010. On that basis, the longer term to be used for comparative purposes would be 27 months, running from October 1, 2008 to December 31, 2010. The Board could also identify that it will be a condition of any future reliability must-run agreement that the agreement contain a provision that allows for cancellation on reasonable terms at any time in the event that Lennox is no longer required for reliability reasons.

ii. The Board could direct OPG and the IESO to submit, with any future reliability must-run agreement that OPG may file for Board approval in the future, the following evidence:

a. the financial costs associated with a reliability must-run agreement that has a term of one year;

b. the financial costs associated with a reliability must-run agreement that has a term of 27 months (from October 1, 2008 to December 31, 2010); and

c. an analysis of any significant differences that may exist in relation to the management of investments in and the operation of Lennox under a one-year agreement versus under a 27-month agreement.

> Such a direction could be given under section 21(1) of the *Ontario Energy Board Act, 1998* and the Board could so indicate in its Decision approving the 2007-08 RMR Agreement.

Board staff recognizes that compliance with this direction may require greater efforts by each of OPG and the IESO in relation to the next reliability must-run agreement for Lennox that may be filed for Board approval. However, were the Board to approve a multi-year agreement, there would be an off-setting reduction in contract negotiation and approval efforts required in the future. In addition, Board staff submits that such incremental efforts are outweighed by the public interest in achieving the most cost-effective outcome.

Adoption of a multi-year approach to reliability must-run agreements may call into question the continued suitability of elements of the existing contract model. In addition, the Board may wish to consider the need for additional new conditions, such as a requirement that the performance of Lennox under the reliability must-run agreement be audited and reported annually to the Board. Board staff believes that these matters can be addressed, as required, as part of the Board's consideration of any future application for approval of a reliability must-run agreement for Lennox. In this regard, Board staff submits that, whatever may be the term of any future reliability must-run agreement, the onus will remain on OPG to satisfy the Board that the agreement should be approved.

All of which is respectfully submitted this 21st day of November, 2007.

Appendix A

Selected Materials Filed by the OPA as part of its Application for Approval of the IPSP (Proceeding EB-2007-0707)

NATURAL GAS-FIRED RESOURCES

1.0 INTRODUCTION

The purpose of this exhibit is to describe how natural gas-fired resources are used in the Plan.

2.0 SUPPLY MIX DIRECTIVE

Q. What does the Supply Mix Directive (the "Directive") state with respect to natural gas-fired resources?

A. The Directive states the following: "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".

Q. Which natural gas-fired applications were considered by the OPA in developing the IPSP?

A. The OPA considered the following natural gas applications for generating electricity:

- New generation located close to loads, of various technologies (simple cycle,[1] combined cycle,[2] combined heat and power[3] and fuel cells[4]);
- Continued operation of, or extension to, current facilities, some under contract to the Ontario Electricity Finance Corporation ("OEFC") or the OPA, and the Lennox generating station;[5] and
- Conversion of some of the coal-fired generating units to operate on natural gas.

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[1] Simple cycle gas turbines (SCGT) produce electricity from the combustion of natural gas to drive a turbine generator. This is a single-stage process.

[2] Combined cycle gas turbines (CCGT) produce electricity from the combustion of natural gas to drive a turbine generator, with the heat produced in this process producing steam that drives a second turbine generator, and thereby produces additional electricity. This is a two-stage process.

[3] Combined heat and power (CHP, also known as cogeneration) produces both electricity, by the combustion of natural gas to drive a turbine generator, and useable thermal energy that is produced by the combustion process. This is a two-stage process.

[4] Fuel cells produce electricity from natural gas in a non-combustion chemical process.

[5] In the dual-fuelled (gas-oil) Lennox generating station, the combustion of natural gas produces steam that drives a conventional steam turbine, producing electricity.

Q. How does the OPA interpret the requirement to maintain the ability to use natural gas-fired generation at peak times?

The OPA interprets this requirement to mean that gas-fired generation is to be available for operation during high demand (peak) hours, which are considered to be the 14% of the hours in the year that have the highest demand, as discussed at Exhibit D-3-1, Attachment 1.

Conceptually, generation from peaking resources will be dispatched after all available lower operating cost resources have been utilized.

There are several technology options and ways of assembling combinations of options in modern natural gas-fired stations. However, there are two basic building blocks for peaking duty: simple-cycle gas turbines ("SCGT") and combined-cycle gas turbines ("CCGT").[6]

Economic considerations result in a preference for SCGT over CCGT as a peaking resource. SCGT generators have relatively low capital costs and relatively high operating (fuel) costs per unit of output, and thus are well-suited to peaking operation where the number of operating hours is small. As a result, SCGT generation facilities are considered the primary option for new peak time natural gas-fired generation, recognizing that in particular cases, other factors, such as transmission or the potential for intermediate duty operation, may result in a preference for CCGT.

There are also peaking duty options regarding existing facilities. Lennox GS currently functions as a peaking resource. The option of continuing its use in relation to the option of replacing its capacity by SCGT generation is addressed in Attachment 1 to this exhibit. There is also the option of converting part of an existing coal-fired facility to

[6] Another natural gas-fired option, CHP, is not considered for peaking duty. Rather, it is considered a baseload resource for present purposes, recognizing that the degree of use of CHP facilities will typically be determined by the applications using their heat energy production, not by electricity requirements.

natural gas. The determining factors in this case relate to cost and timing of natural gas infrastructure and electricity transmission in the local area.

Q. How does the OPA interpret the requirement for high efficiency use of the fuel?

A. The OPA considers high efficiency natural gas use to be electricity supply from CCGT, and combined heat and power generators (“CHP”). CCGT and CHP generators have significantly higher energy efficiency than SCGT for the conversion of natural gas to electrical energy. Generation from other technologies that can efficiently use natural gas, such as fuel cells, if they become commercially feasible, would also be considered high efficiency.

The amount of high efficiency resources will depend on economic considerations. The economic characteristics of CCGT generators (relatively high capital costs and lower operating costs, in comparison with SCGT) means that they are preferred over SCGT generators to meet intermediate resource requirements. The economic and operational characteristics of CHP generation make it more suitable for meeting baseload requirements.

Q. How does the OPA interpret the requirement for high value use of the fuel?

The OPA considers “high-value” use to be applications for which natural gas-fired resources provide a material advantage over alternatives, or are the only feasible choice, for example having acceptable lead times. Such an advantage may take the form of lower cost, enhanced flexibility, shorter lead times, improved system operability, or enhanced environmental performance.

An example of high value use occurs when an SCGT or CCGT facility that is required for overall system adequacy is sited in a location where it provides additional benefits in the form of local area reliability and avoided local area transmission reinforcement costs. Other examples are taking advantage of short lead times to replace coal-fired generation at the earliest practical time and to respond to uncertainties.

Gas-fired peaking resources can also provide high value as a source of operating reserve, being both an economic resource and having the required technical characteristic of inherently short times for ramping their capacity output up or down. In this role of operating reserve, these generators are called upon to generate electricity in small amounts to balance the needs of the system. The requirement for ramp capability arises as coal-fired capacity (which now provides that capability) is retired, and as wind is integrated in larger amounts. Peaking resources are not limited to operation at peak times; they provide value as a resource that is available at other times in the event of planned or unplanned outages of lower cost resources.

Q. How does the IPSP meet the Directive with respect to natural gas-fired resources?

A. The Plan includes natural gas capacity from SCGT generation for peak-time use, CCGT and CHP generation for high efficiency use, and all three generation types for high value use.

In general terms, natural gas-fired resources, by virtue of their characteristics of flexibility and availability, are the principal source of flexibility for the Ontario system as a whole. The currently committed gas-fired resources will contribute to Ontario meeting reliability requirements while replacing coal-fired generation. They are also available to respond to uncertainties in assumptions, such as those relative to nuclear performance, higher load growth, delays in acquiring new resources, and nuclear refurbishment decisions.

While the Plan presents specific amounts, timing and types of natural gas-fired resources, these resources should be considered as part of a generic natural gas resource portfolio that will become progressively transformed into specific resources at the times in the future when specific resource decisions are made. This generic portfolio also includes the resources in the Plan (CHP, NUG, CCGT, SCGT and Lennox), and adding additional capacity at existing generation sites. It also includes the option of converting coal-fired gas units at Nanticoke to natural gas, which is not included in the Plan but nevertheless remains an option.

The planned contribution of natural gas-fired resources is summarized in Table 1 and Table 2, for the scenarios of the Pickering B nuclear station refurbished, and for it not being refurbished, respectively:

Table 1: Natural Gas-Fired Resources – Pickering B Refurbished (Installed MW)

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
BASELOAD																					
Existing	1,658	1,658	1,658	1,658	1,658	1,658	1,493	1,493	1,189	1,142	936	602	602	602	602	471	471	471	471	471	471
Committed	0	31	178	414	414	414	414	414	414	414	414	414	414	414	414	414	414	414	414	414	414
Planned (CHP)	0	0	0	0	0	0	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586
Baseload Total	1,658	1,689	1,836	2,072	2,072	2,072	2,493	2,493	2,189	2,143	1,937	1,602	1,602	1,602	1,602	1,471	1,471	1,471	1,471	1,471	1,471
INTERMEDIATE																					
Existing	1,271	1,271	1,271	1,271	1,271	1,271	1,271	1,271	1,271	1,211	1,211	1,090	1,090	1,090	1,090	1,090	1,090	1,090	1,090	1,090	1,090
Committed	0	250	3,253	3,853	3,853	3,853	3,853	3,853	3,853	3,853	3,853	3,853	3,853	3,853	3,853	3,853	3,853	3,853	3,853	3,853	3,853
Planned (CCGT)	0	0	0	0	0	0	1,015	1,015	1,319	1,319	1,319	1,319	1,319	1,319	1,319	1,319	1,319	1,319	1,319	1,319	1,319
Intermediate Total	1,271	1,521	4,524	5,124	5,124	5,124	6,139	6,139	6,443	6,383	6,383	6,262	6,262	6,262	6,262	6,262	6,262	6,262	6,262	6,262	6,262
PEAKING																					
Existing	2,174	2,174	2,174	2,174	69	69	69	69	69	69	69	69	69	69	69	69	69	69	69	69	69
Committed	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Planned (SCGT, Lennox)	0	0	0	0	2,455	2,905	2,905	3,455	3,455	3,455	3,455	3,705	3,705	3,180	3,180	2,655	2,655	2,655	2,655	2,655	3,055
Peaking Total	2,174	2,174	2,174	2,174	2,524	2,974	2,974	3,524	3,524	3,524	3,524	3,774	3,774	3,249	3,249	2,724	2,724	2,724	2,724	2,724	3,124
TOTAL	5,103	5,384	8,534	9,370	9,720	10,170	11,607	12,157	12,157	12,050	11,844	11,639	11,639	11,114	11,114	10,458	10,458	10,458	10,458	10,458	10,858

Source: OPA.

Table 2: Natural Gas-Fired Resources – Pickering B Not Refurbished (Installed MW)

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
BASELOAD																					
Existing	1,658	1,658	1,658	1,658	1,658	1,658	1,493	1,493	1,189	1,142	936	602	602	602	602	471	471	471	471	471	471
Committed	0	31	178	414	414	414	414	414	414	414	414	414	414	414	414	414	414	414	414	414	414
Planned (CHP)	0	0	0	0	0	0	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586
Baseload Total	1,658	1,689	1,836	2,072	2,072	2,072	2,493	2,493	2,189	2,143	1,937	1,602	1,602	1,602	1,602	1,471	1,471	1,471	1,471	1,471	1,471
INTERMEDIATE																					
Existing	1,271	1,271	1,271	1,271	1,271	1,271	1,271	1,271	1,271	1,211	1,211	1,090	1,090	1,090	1,090	1,090	1,090	1,090	1,090	1,090	1,090
Committed	0	250	3,253	3,853	3,853	3,853	3,853	3,853	3,853	3,853	3,853	3,853	3,853	3,853	3,853	3,853	3,853	3,853	3,853	3,853	3,853
Planned (CCGT)	0	0	0	0	0	0	1,015	1,015	1,319	1,426	1,632	2,087	2,212	2,212	2,212	2,212	2,212	2,212	2,212	2,212	2,468
Intermediate Total	1,271	1,521	4,524	5,124	5,124	5,124	6,139	6,139	6,443	6,490	6,696	7,030	7,155	7,155	7,155	7,155	7,155	7,155	7,155	7,155	7,411
PEAKING																					
Existing	2,174	2,174	2,174	2,174	69	69	69	69	69	69	69	69	69	69	69	69	69	69	69	69	69
Committed	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Planned (SCGT, Lennox)	0	0	0	0	2,455	2,905	2,905	3,455	3,455	3,455	3,780	4,030	4,030	4,030	2,980	1,930	1,930	1,930	1,930	1,930	1,930
Peaking Total	2,174	2,174	2,174	2,174	2,524	2,974	2,974	3,524	3,524	3,524	3,849	4,099	4,099	4,099	3,049	1,999	1,999	1,999	1,999	1,999	1,999
TOTAL	5,103	5,384	8,534	9,370	9,720	10,170	11,607	12,157	12,157	12,157	12,482	12,732	12,857	12,857	11,807	10,626	10,626	10,626	10,626	10,626	10,882

Source: OPA.

3.0 REQUIRED RESOURCES

Q. How did the OPA determine the requirement for gas-fired resources?

A. The OPA adopted the following three-step approach to determine the requirement for gas-fired resources:

Step 1 - Determine the contribution from existing and committed gas-fired resources;

Step 2 - Determine the remaining requirement for gas-fired resources, by taking the total resource requirement (including both peak demand and planning reserve requirements [7]), and subtracting the contribution from all existing and committed resources, and planned conservation and non-gas supply resources; and

Step 3 - Allocate this remaining requirement for gas-fired resources among CHP, Lennox, SCGT and CCGT.

3.1 Step 1: Contribution of Existing and Committed Resources

3.1.1 Contribution of Existing Natural Gas-Fired Resources

Q. What was the installed capacity of the existing natural gas-fired resources from 2003 to 2007, and what is their associated energy production?

A. The installed capacity of the existing natural gas-fired from 2003 to 2007 is shown in Table 3 below.[8] The current capacity of natural gas-fired resources is 5,103 MW.

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[7] Exhibit D-2-1 addresses the determination of planning reserve requirement. This requirement will be met by a combination of peaking and intermediate resources (i.e., SCGT and CCGT).

[8] Existing resources (MW) are as of June 1, 2007. The numbers in Table 1 include 2,100 MW of gas-oil dual-fuelled resources and 74 MW of oil-fired resources.

The four 525 MW units at Lennox GS have the capability to operate on either natural gas or oil fuel, and are thus considered to be dual-fuelled. However, during recent years Lennox has been operated predominantly on natural gas, and is assumed to do so in the future.

Oil-fired resources have similar operating and economic characteristics to SCGT and are therefore included in the summary as peaking resources. There are oil-fired combustion turbine generating units, located at generating stations (Bruce GS, Darlington GS, Lennox GS, and Lambton GS), and at one transmission facility (Kingsville), which are used primarily as a source of backup power supply for these facilities. The capacity values associated with these facilities in the IPSP are the amounts that the IESO considers to be available as system resources.

Table 3: Existing Natural Gas-Fired Capacity and Energy Production, 2003-2007

	2003	2004	2005	2006	2007
Installed MW	4,416	4,364	4,976	5,103	5,103
Energy TWh/yr	N/A	12.3	13.0	11.8	N/A

Source: 2007 Data from OPA. Historic installed MW from IESO 18-month outlook for mid-year month. Energy numbers, where available, are from January IESO news releases on consumption and demand numbers.

The specific facilities are shown in Table 4 below.[9]

[9] For additional detail see http://www.powerauthority.on.ca/Page.asp?PageID=924&SiteNodeID=236.

Table 4: Existing Natural Gas-Fired and Oil-Fired Facilities (Installed Capacity – MW)

Gas/Oil Dual Fired CST*	
Lennox	**2,100**
Natural Gas-Fired CHP	
Cardinal Power	184
Dow Chemical	100
Fort Frances	105
GTAA Cogen Plant	117
Invista - Maitland	50
Kingston Cogen	140
Lake Superior Power	120
Northland - Iroquois Falls	131
Tractebel - West Windsor	128
Transalta - Ottawa	72
Transalta - Windsor	78
Whitby Cogen	56
	1,281
Natural Gas-Fired CCGT	
Brighton Beach	580
EPCOR - Kapuskasing	60
EPCOR - Nipigon	43
EPCOR - North Bay	60
EPCOR - Tunis	60
Northland Kirkland Lake	149
Transalta - Mississauga	138
Transalta - Sarnia	510
	1,601
Oil-Fired CTU	
Bruce	24
Darlington	22
Kingsville	10
Lambton	14
Lennox	5
	74
Natural Gas/Woodwaste	
Northland - Cochrane	**47**
TOTAL	**5,103**

Source: OPA. * Conventional steam turbines.

Q. What are the assumed operating lives of these existing facilities and what is the basis for these assumptions?

A. The assumed operating lives are as follows:

Lennox Generating Station

All four units totalling 2,100 MW, at Lennox GS are assumed to remain in operation until 2020. The need for the capacity provided by Lennox GS is reduced beginning in 2020, as a result of the addition of new renewable and conservation resources.

Lennox GS is currently operating under a Reliability Must-Run ("RMR") contract with the IESO that will expire in October 2008. This contract was required in order for Lennox to remain in operation for local reliability purposes. The OPA has assessed whether Lennox GS should remain in service after the expiry of this contract. This assessment is presented in Attachment 1 to this exhibit. The economic analysis shows that keeping Lennox GS in service is more economic than the cost of alternative replacement generation based on new SCGT facilities. The operating efficiency of Lennox fuelled by natural gas is comparable to that of an SCGT facility, and Lennox has a substantial economic advantage as a result of avoiding the capital costs that would be required for new SCGT facilities, as well as the costs of associated natural gas infrastructure. Lennox is also seen to be more economic than the alternative of CCGT facilities, which would be operated as intermediate resources.

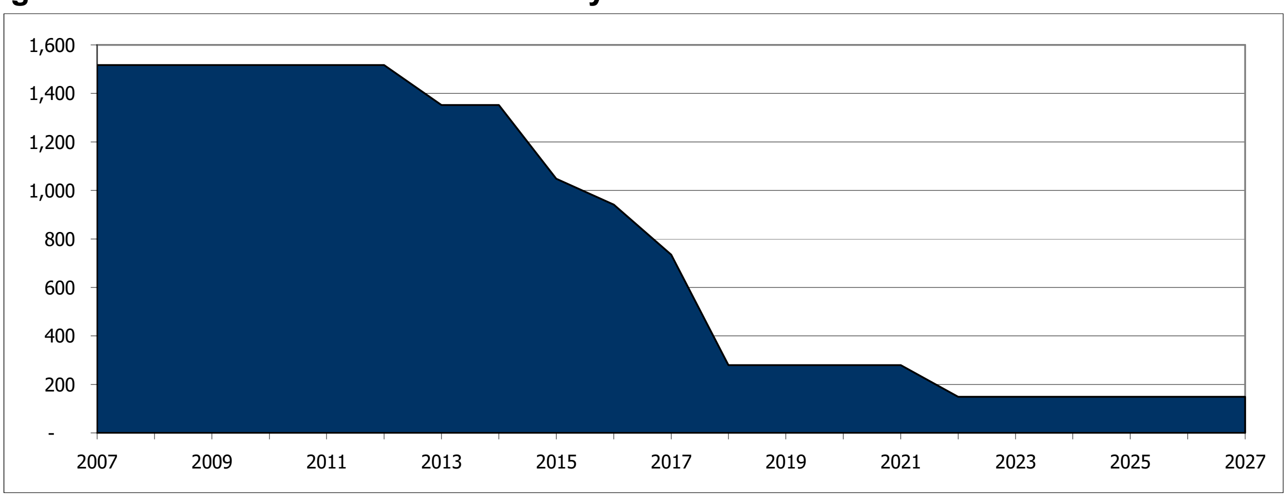
While Lennox is assumed to remain in service, its category changes from an existing resource to a planned resource in 2011. This is a result of Lennox, and therefore its RMR contract, not being needed for local reliability purposes after 2010. This treatment is consistent with that used for NUG resources whose contracts expire during the planning period. The need for Lennox will be reviewed in successive Plans.

Non-Utility Generation

In the late 1980s and early 1990s, Ontario Hydro entered into approximately 90 power purchase agreements ("PPAs") with other generators for energy produced from the facilities they owned. Because this generation was not owned by Ontario Hydro, it was known as non-utility generation ("NUG"). This term is used in many North American jurisdictions where utilities likewise entered into PPAs with independent generators. The major portion of this generation in Ontario is natural gas-fired.

Approximately 1,517 MW of gas-fired generation are under NUG contracts administered by the OEFC. Contracts representing 1,367 MW will expire within the period to 2027. The decline in gas-fired NUG capacity under contract is shown in the following figure.

Figure 1: Decline in Gas-Fired Non-Utility Generation Under Contract



Source: OPA.

These NUG units are operated in various ways, but for the purpose of this assessment they are considered to be baseload generation, as a result of incentives to do so in the contracts the owners of these units currently have with the OEFC. The IPSP assumes that the capacity represented by those contracts will continue to be physically available, and can be operated as peaking (SCGT), intermediate (CCGT), or baseload (CHP) resources. There are several options available for these facilities at contract expiration.

From a system need perspective there are requirements for facilities, whose contracts expire by 2015, to continue. The need for facilities whose contracts expire beyond 2015 is less clear and will be examined in future plans. For the purposes of this Plan, it is assumed that contracts expiring by 2015 are renewed, and those beyond 2015 are not.

The need for this capacity will be reviewed in successive Plans and a determination will be made regarding the requirement for additional capacity. If additional capacity is required, a decision will be made regarding the most appropriate redevelopment options and means of procuring this capacity, including the option of renegotiating NUG contracts.

Other Existing Gas-Fired Generation

Existing non-NUG gas-fired generators (representing 1,412 MW, as illustrated in Table 5) are assumed to have an operating life of 20 years. There are also non-operating facilities that could be brought into service over the period of the Plan.

Table 5: Existing Non-NUG Gas-Fired Generators (Installed Capacity – MW)

Natural Gas-Fired CHP	
GTAA Cogen Plant	117
Dow Chemical	100
Fort Frances	105
Natural Gas-Fired CCGT	
Brighton Beach	580
Transalta - Sarnia	510
TOTAL	**1,412**

Source: OPA

As such, they would reach the end of their assumed operating lives in the final years of the Plan. Assessments of the operation of these facilities will be updated in future Plans.

3.1.2 Contribution of Committed Natural Gas-Fired Resources

Q. What is the installed capacity of committed natural gas-fired resources?

A. The currently committed natural gas-fired capacity (installed basis) totals 4,267 MW, as shown below. A committed resource is a resource not yet in service as of June 1, 2007 that has a signed procurement contract with the OPA.

Table 6: Committed Natural Gas-Fired Resources (Installed Capacity – MW)

Facility	MW	In-Service
CCGT		
St. Clair Energy Centre	570	2009
Greenfield Energy Centre	1,005	2009
Greenfield South Power Plant	280	2009
Goreway Power	860	2009
Portlands Energy Centre	538	2009
Halton Hills Generating Station	600	2010
Total CCGT	**3,853**	
CHP		
Great Northern Tri-Gen Facility	12	2008
East Windsor Cogeneration Centre	84	2009
Durham College CHP District Energy Project	2	2008
Thorold Cogeneration Project	236	2010
Countryside London Cogeneration Facility	12	2008
Algoma Energy By-Product Cogeneration Facility	63	2009
Warden Energy Centre	5	2008
Total CHP	**414**	
Total Committed Gas	**4,267**	

Source: OPA

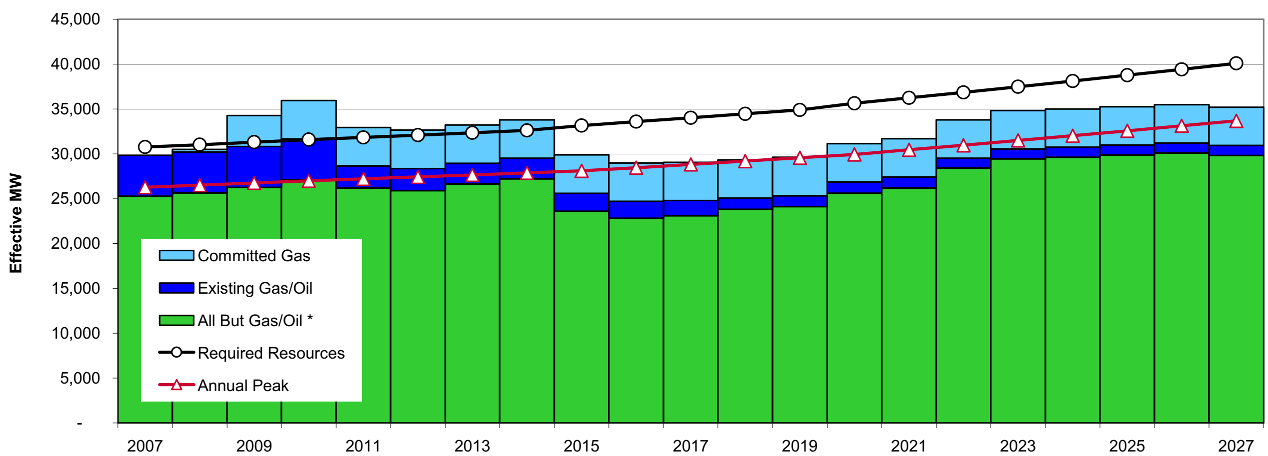
Q. What are the assumed operating lives of these committed facilities and what is the basis for these assumptions?

A. These committed facilities are assumed to remain in operation throughout the 20-year period of the Plan, consistent with the procurement contracts for these resources.

3.2 Step 2: Determine the remaining resource requirement for natural gas-fired resources

Step 2 is summarized in Figure 2, Table 7, Figure 3, and Table 8. This is presented for two cases (with and without Pickering B refurbishment) that have different requirements for natural gas-fired resources:

Figure 2: Required Gas-Fired Resources – Assuming Pickering B Refurbished



Source: OPA. "All But Gas/Oil" is all existing, committed and planned resources, including interconnection, but excluding gas/oil and unspecified resources.

In Figure 2, the lower line shows system peak demand, while the upper line shows the total resource requirement, by including the reserve requirement. The top envelope of the bars shows the resources planned to be available from other than planned gas-fired resources (new CCGT and CCGT resources, NUG replacement, Lennox, and unspecified resources). The space between the upper line and the top portion of the bars is the "gap", that is, the resources to be met by planned gas-fired resources, from a combination of Lennox and new CHP, SCGT and CCGT facilities, NUG replacement, and unspecified resources. The gap emerges in 2015, and persists through the remainder of the period of the Plan.

Table 7 shows the corresponding numerical detail. The gap, for the case of Pickering B refurbished, peaks at 5,265 MW in 2019 (3,165 MW if Lennox is excluded).[10]

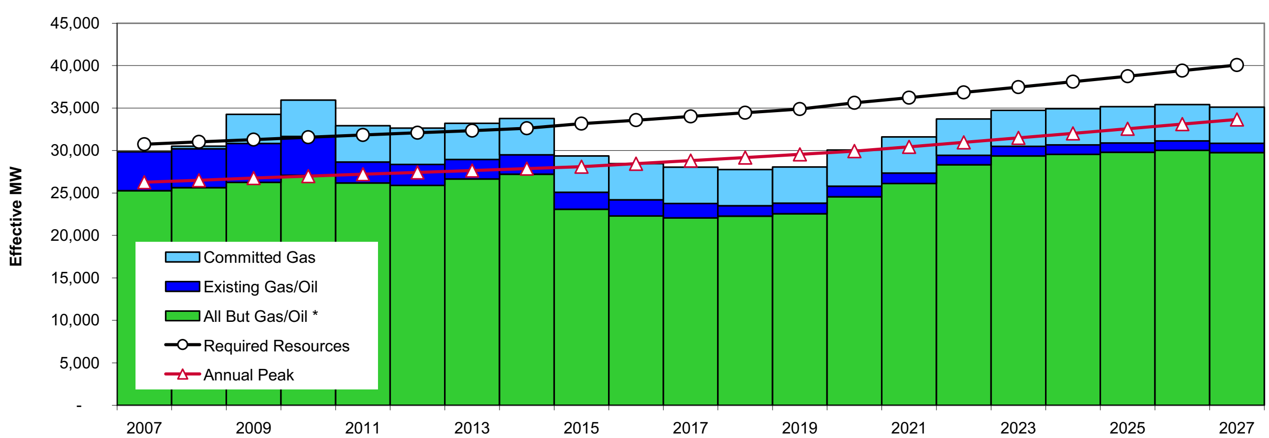
Table 7: Required Gas-Fired Resources – Assuming Pickering B Refurbished

Effective MW	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
All But Gas/Oil *	25,265	25,642	26,245	27,084	26,193	25,896	26,637	27,205	23,605	22,805	23,106	23,813	24,112	25,621	26,178	28,400	29,439	29,624	29,870	30,100	29,813
Existing Gas/Oil	4,578	4,578	4,578	4,578	2,473	2,473	2,308	2,308	2,004	1,897	1,691	1,236	1,236	1,236	1,236	1,105	1,105	1,105	1,105	1,105	1,105
Committed Gas	0	281	3,431	4,267	4,267	4,267	4,267	4,267	4,267	4,267	4,267	4,267	4,267	4,267	4,267	4,267	4,267	4,267	4,267	4,267	4,267
Annual Peak	26,282	26,515	26,749	26,986	27,205	27,426	27,648	27,873	28,099	28,457	28,820	29,187	29,559	29,936	30,444	30,960	31,485	32,020	32,563	33,115	33,677
Required Resources	30,750	31,022	31,296	31,573	31,830	32,088	32,349	32,611	33,157	33,580	34,008	34,441	34,880	35,624	36,228	36,843	37,468	38,103	38,750	39,407	40,076
Total Available	29,843	30,500	34,254	35,929	32,933	32,636	33,212	33,781	29,876	28,969	29,065	29,316	29,615	31,124	31,681	33,772	34,811	34,996	35,242	35,472	35,185
Gap	**907**	**522**	**0**	**0**	**0**	**0**	**0**	**0**	**3,281**	**4,610**	**4,943**	**5,124**	**5,265**	**4,500**	**4,547**	**3,071**	**2,656**	**3,107**	**3,507**	**3,935**	**4,891**

Source: OPA. * All existing, committed and planned resources, including interconnection, but excluding gas/oil and unspecified resources. Total Available is all existing and committed resources, and planned conservation and non-gas supply resources.

Figure 3 illustrates the gas-fired resource gap for the case of Pickering B not refurbished.

Figure 3: Required Gas-Fired Resources – Assuming Pickering B Not Refurbished



Source: OPA. "All But Gas/Oil" is all existing, committed and planned resources, including interconnection, but excluding gas/oil and unspecified resources. Total Available is all existing and committed resources, and planned conservation and non-gas supply resources.

10 Resource requirements are given in Exhibit D-3-1.

Table 8 lists the corresponding numerical detail. The gap, for the case of Pickering B not refurbished, peaks at 6,813 MW in 2019 (4,713 MW if Lennox is excluded).[11]

Table 8: Required Gas-Fired Resources – Assuming Pickering B Not Refurbished

Effective MW	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
All But Gas/Oil *	25,265	25,642	26,245	27,084	26,193	25,896	26,637	27,205	23,089	22,289	22,074	22,265	22,564	24,557	26,114	28,336	29,375	29,560	29,806	30,036	29,749
Existing Gas/Oil	4,578	4,578	4,578	4,578	2,473	2,473	2,308	2,308	2,004	1,897	1,691	1,236	1,236	1,236	1,236	1,105	1,105	1,105	1,105	1,105	1,105
Committed Gas	0	281	3,431	4,267	4,267	4,267	4,267	4,267	4,267	4,267	4,267	4,267	4,267	4,267	4,267	4,267	4,267	4,267	4,267	4,267	4,267
Annual Peak	26,282	26,515	26,749	26,986	27,205	27,426	27,648	27,873	28,099	28,457	28,820	29,187	29,559	29,936	30,444	30,960	31,485	32,020	32,563	33,115	33,677
Required Resources	30,750	31,022	31,296	31,573	31,830	32,088	32,349	32,611	33,157	33,580	34,008	34,441	34,880	35,624	36,228	36,843	37,468	38,103	38,750	39,407	40,076
Total Available	**29,843**	**30,500**	**34,254**	**35,929**	**32,933**	**32,636**	**33,212**	**33,781**	**29,360**	**28,453**	**28,033**	**27,768**	**28,067**	**30,060**	**31,617**	**33,708**	**34,747**	**34,932**	**35,178**	**35,408**	**35,121**
Gap	907	522	0	0	0	0	0	0	3,797	5,126	5,975	6,672	6,813	5,564	4,611	3,135	2,720	3,171	3,571	3,999	4,955

Source: OPA. * All existing, committed and planned resources, including interconnection, but excluding gas/oil and unspecified resources.

3.3 Step 3: Allocation of Remaining Gas-Fired Resource Requirements

Q. How are the gas-fired resource requirements allocated between Lennox, CHP, SCGT and CCGT resources?

A. Step 3 addresses the allocation as shown in Table 9.

The first step is to include Lennox as a planned resource beginning in 2011, with reduced need for its capacity beginning in 2020. As described previously, the continued operation of Lennox was found to be justified. However, the nature of that justification respecting the RMR contract led to Lennox being re-classified to a planned resource in 2011. This is consistent with the treatment of NUG facilities whose OEFC contracts expire.

The second step is to determine the amount of CHP to be assumed in the Plan. The planned amount, as illustrated in Table 1 and in Table 2, is 586 MW. The amount of committed CHP is 414 MW (as shown in Table 6). Therefore, the total committed and planned amount of CHP in the Plan is 1,000 MW. This assessment reflects experience in Ontario in acquiring CHP resources, and recognizes that the expected amount of CHP is constrained by the limited potential for economic applications for the heat that is

[11] The difference in the gap between the two Pickering B cases is seen to be substantially less than the 2,000 MW capacity of the station. The difference is due to system resources in relation to system demand being different in the two years.

co-produced with the electricity. The potential for CHP is recognized as being uncertain and will be assessed in future Plans.

The final step is to apportion the remaining planned requirements between SCGT and CCGT, as shown below in Table 9.

Table 9: 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. 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.

The capacities and dates beyond 2015 are to be viewed as less definite than those in earlier years.

The apportionment of requirements between SCGT and CCGT resources was informed by the break-even analysis for meeting intermediate and peak resource requirements as set out in Exhibit D-3-1, Attachment 1, where SCGT would be the preferred resource for meeting peak time demand and planning reserve. However, other factors were considered:

- The overall needs and characteristics of the system lead to a preference for SCGT rather than CCGT for Northern York Region and Kitchener-Waterloo-Cambridge-Guelph;
- There is a remaining need on system adequacy grounds for 1,400 MW of generation. Southwest GTA is an area of high load growth where major transmission reinforcement is required, but could be deferred to beyond 2027 by the addition of up to 900 MW of new generation. It is therefore appropriate to locate a portion (850 MW is included in the Plan) of the required additional generation in Southwest GTA. This new generation could be either CCGT or SCGT, although there is a preference for CCGT, on the basis of expected energy production, and as a backup in the event other new resources do not materialize. CCGT would also provide "energy insurance".[12] In the Plan this resource is modelled as CCGT;
- The 550 MW attributed to GTA in Table 9 refers to the remainder of the 1,400 MW, after the deduction of the 850 MW in Southwest GTA. This amount may or may not be located in the Southwest GTA. Location in the GTA has the general benefit of addressing the supply-load mismatch in the GTA, as well as mitigating risks specific to the GTA, such as Pickering B not being refurbished, and conservation in the GTA being less than planned. It would also provide voltage support by virtue of being located close to loads.[13] The new generation could be either CCGT or SCGT, but is modelled as CCGT; and
- Conversion of coal-fired facilities to natural gas use, especially at Nanticoke, is recognized as an alternative to CCGT or SCGT, and an option to be considered in the future. However, current analysis[14] shows that other generation is more cost effective, and would enable the earlier replacement of coal. Conversion of Nanticoke is not assumed in the Plan at this time.

The resources that would come into service in 2017 and beyond are called "unspecified" or "proxy gas" in the IPSP. These terms are used to denote resources of unspecified type, required for a period well beyond the near term; if the need for the resources persists into future Plans, the decisions made at that time may be for natural gas-fired generation or an alternative resource, such as a firm purchase. This approach reflects the fact that in this IPSP there is no need to specify a type of resource. For modelling

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[12] Exhibit G-1-1 identifies the significant range of energy production required from gas-fired generation under a range of planning scenarios. The scenarios illustrate a variety of long-term planning uncertainties and identify a requirement for "energy insurance", which would be more appropriately provided by CCGT rather than SCGT resources.

[13] Voltage support is in the form of reactive power associated with the new generation. The effectiveness of reactive power diminishes sharply with increasing distance from the generator.

[14] See Exhibit E-2-5, Enabling Natural Gas; Exhibit E-5-1, Northern York Region; Exhibit E-5-2, Kitchener-Waterloo-Cambridge-Guelph; and Exhibit E-5-3, Southwest GTA.

and costing purposes in this IPSP, the resources are assumed to be natural gas-fired generation (SCGT or CCGT). However, there are no near-term actions associated with these proxy gas resources.

The planned new gas-fired resources are shown in Table 10, Table 11, Figure 4, and Figure 5.

Table 10: Planned Natural Gas-Fired Generation: Pickering B Refurbished

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Lennox	-	-	-	-	2,100	2,100	2,100	2,100	2,100	2,100	2,100	2,100	2,100	1,575	1,575	1,050	1,050	1,050	1,050	1,050	1,050
CHP	-	-	-	-	-	-	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586
Northern York Region	-	-	-	-	350	350	350	350	350	350	350	350	350	350	350	350	350	350	350	350	350
Kitchener-Waterloo-Cambridge-Guelph	-	-	-	-	-	450	450	450	450	450	450	450	450	450	450	450	450	450	450	450	450
Southwest GTA	-	-	-	-	-	-	850	850	850	850	850	850	850	850	850	850	850	850	850	850	850
GTA	-	-	-	-	-	-	-	550	550	550	550	550	550	550	550	550	550	550	550	550	550
NUG Replacement	-	-	-	-	-	-	165	165	469	469	469	469	469	469	469	469	469	469	469	469	469
Unspecified/Proxy Gas	-	-	-	-	-	-	-	-	-	-	-	250	250	250	250	250	250	250	250	250	650
TOTAL	**0**	**0**	**0**	**0**	**2,450**	**2,900**	**4,501**	**5,051**	**5,355**	**5,355**	**5,355**	**5,605**	**5,605**	**5,080**	**5,080**	**4,555**	**4,555**	**4,555**	**4,555**	**4,555**	**4,955**

Source: OPA.

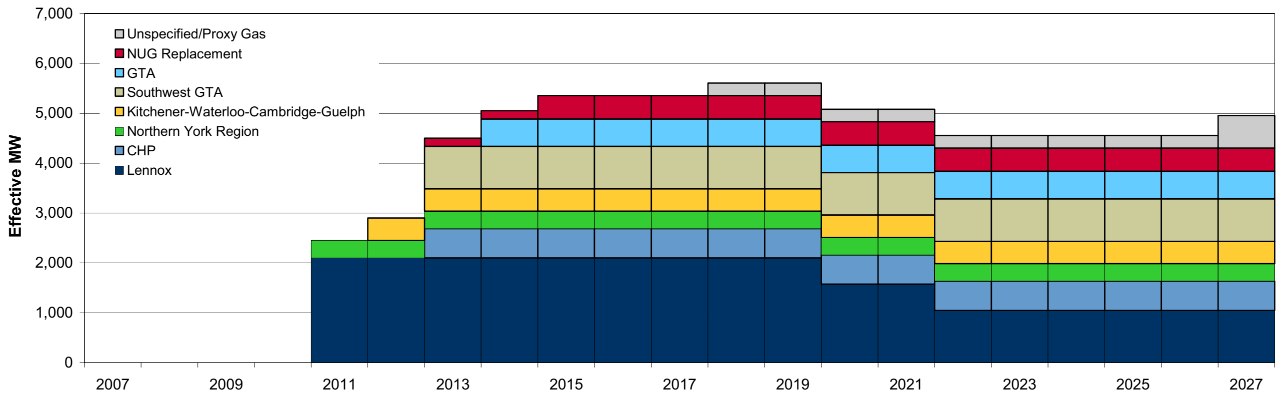
Table 11: Planned Natural Gas-Fired Generation: Pickering B Not Refurbished

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Lennox	-	-	-	-	2,100	2,100	2,100	2,100	2,100	2,100	2,100	2,100	2,100	2,100	1,050	-	-	-	-	-	-
CHP	-	-	-	-	-	-	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586
Northern York Region	-	-	-	-	350	350	350	350	350	350	350	350	350	350	350	350	350	350	350	350	350
Kitchener-Waterloo-Cambridge-Guelph	-	-	-	-	-	450	450	450	450	450	450	450	450	450	450	450	450	450	450	450	450
Southwest GTA	-	-	-	-	-	-	850	850	850	850	850	850	850	850	850	850	850	850	850	850	850
GTA	-	-	-	-	-	-	-	550	550	550	550	550	550	550	550	550	550	550	550	550	550
NUG Replacement	-	-	-	-	-	-	165	165	469	576	782	1,237	1,237	1,237	1,237	1,237	1,237	1,237	1,237	1,237	1,368
Unspecified/Proxy Gas	-	-	-	-	-	-	-	-	-	-	325	575	700	700	700	700	700	700	700	700	825
TOTAL	**0**	**0**	**0**	**0**	**2,450**	**2,900**	**4,501**	**5,051**	**5,355**	**5,462**	**5,993**	**6,698**	**6,823**	**6,823**	**5,773**	**4,723**	**4,723**	**4,723**	**4,723**	**4,723**	**4,979**

Source: OPA.

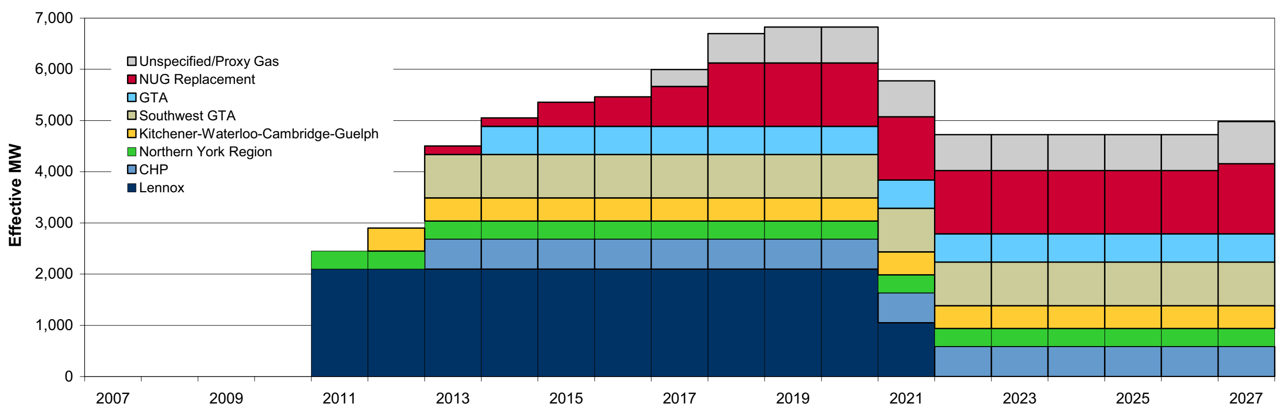
There is seen to be up to about 1,700 MW of additional gas-fired resources in the case of Pickering B not refurbished. This is provided by NUG replacement, proxy gas and Lennox.

Figure 4: Planned Natural Gas-Fired Generation: Pickering B Refurbished



Source: OPA.

Figure 5: Planned Natural Gas-Fired Generation: Pickering B Not Refurbished



Source: OPA.

Q. Are there planned gas-fired facilities that are intended to be procured by 2010?

A. Gas-fired generation to be procured by 2010 is described at Exhibit E-5-1, Northern York Region; Exhibit E-5-2, Kitchener-Waterloo-Cambridge-Guelph; and Exhibit E-5-3, Southwest GTA. The capacity and in-service dates of these planned resources are shown in Table 9.

Q. To what extent was stakeholder input considered in arriving at the composition of the natural gas-fired resources portfolio? What were the key issues and how did the OPA address them?

A. Stakeholder input respecting natural gas-fired resources, described in detail in Exhibit C-4-1, includes the following:

Some stakeholders questioned the appropriateness of the gas price forecasts used by the OPA. Exhibit D-3-1, Attachment 4, examines this matter and affirms the appropriateness of the forecasts.

Some stakeholders stated that the amount of natural gas to be used for electricity generation would stress the natural gas delivery infrastructure in Ontario and Western Canada, with the potential for tightening the gas supply available to existing users. The OPA notes that the OEB staff reviewed the implications of planned use of natural gas for generating electricity, as reported in its 2005 NGEIR study. The OEB staff concluded that infrastructure investment in the order of $315 million to $675 million would be required in Ontario, and $210 million to $255 million "upstream". This is for the NGEIR medium scenario, which has natural gas requirements comparable to those included in the IPSP. It was also concluded that existing cost allocation processes are adequate for such investment. These upgrades are currently under development.

Other stakeholders advised limiting the use of natural gas for generating electricity for other reasons, namely to avoid upward pressure on gas prices that would be to the detriment of existing users of natural gas. There would also be additional cost exposure resulting from gas price volatility.

In response to such concerns, the OPA is conducting further studies on these issues.

There were also concerns expressed regarding the implication of the CO_2 emissions associated with the generation.

Some stakeholders expressed a contrary view that stressed the positive attributes of natural gas as a short lead time resource, having flexibility as to its location, and being cleaner than coal and preferable to nuclear.

The location of the planned gas-fired resources is shown in Figure 6:

Figure 6: Location of Planned Gas-Fired Resources

Source: OPA

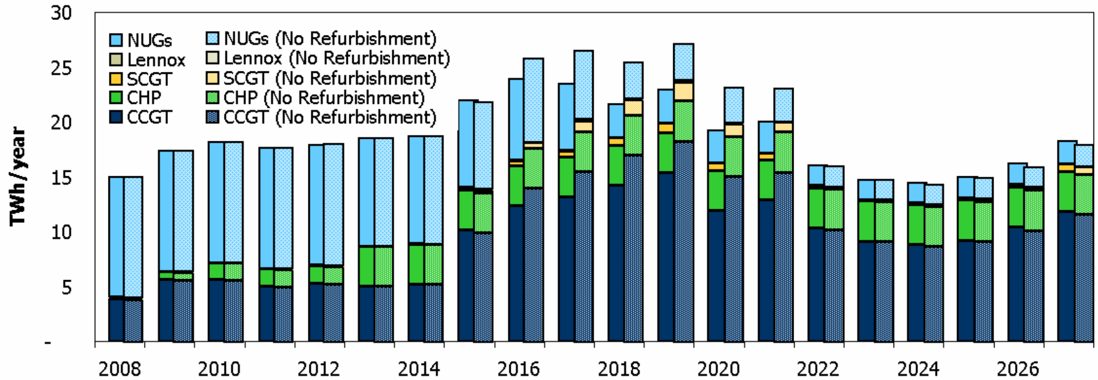
The energy production is shown in Table 12 and Figure 7:

Table 12: Natural Gas-Fired Resources (Energy - TWh)

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
CCGT	3.8	5.6	5.5	5.0	5.2	5.0	5.2	10.0	12.3	13.1	14.2	15.3	11.9	12.8	10.3	9.1	8.8	9.2	10.3	11.8
CHP	0.1	0.7	1.6	1.6	1.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6
SCGT	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.3	0.4	0.6	0.7	0.8	0.7	0.6	0.2	0.1	0.2	0.3	0.3	0.7
Lennox	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NUGs	11.0	11.0	11.0	11.0	11.0	9.9	9.9	8.0	7.4	6.1	3.0	3.1	3.0	2.9	1.9	1.8	1.9	1.9	1.9	2.1
Total TWh/year	**15.0**	**17.3**	**18.1**	**17.6**	**17.9**	**18.5**	**18.7**	**21.9**	**23.9**	**23.4**	**21.6**	**22.9**	**19.2**	**20.0**	**16.1**	**14.7**	**14.5**	**15.0**	**16.2**	**18.2**
CCGT (No Refurbishment)	3.8	5.6	5.5	5.0	5.2	5.0	5.2	9.8	13.9	15.4	16.9	18.2	14.9	15.3	10.2	9.1	8.6	9.0	10.1	11.5
CHP (No Refurbishment)	0.1	0.7	1.6	1.6	1.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6
SCGT (No Refurbishment)	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.3	0.5	1.0	1.4	1.7	1.1	0.9	0.2	0.1	0.2	0.2	0.3	0.7
Lennox (No Refurbishment)	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NUGs (No Refurbishment)	11.0	11.0	11.0	11.0	11.0	9.9	9.9	8.0	7.6	6.3	3.3	3.4	3.2	3.1	1.9	1.8	1.9	1.9	1.9	2.1
Total TWh/year (No Refurbishment)	**15.0**	**17.3**	**18.1**	**17.6**	**17.9**	**18.5**	**18.7**	**21.8**	**25.7**	**26.4**	**25.3**	**27.0**	**23.0**	**23.0**	**15.9**	**14.7**	**14.2**	**14.8**	**15.9**	**17.9**

Source: OPA.

Figure 7: Natural Gas-fired Resources (Energy - TWh)

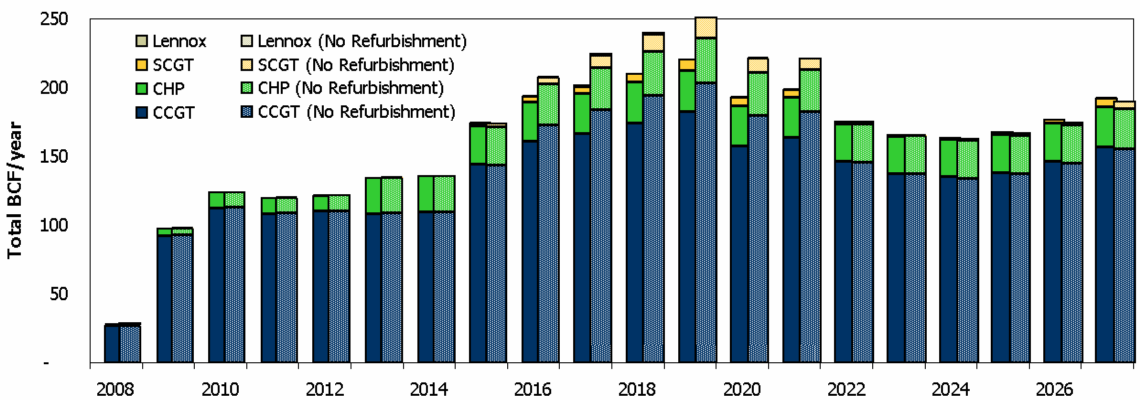


Source: OPA.

Energy production increases over the next decade, but declines to near current levels in the later years of the Plan.

Annual gas consumption, which mirrors energy production, is shown in Figure 8.

Figure 8: Natural Gas Consumption – With/Without Pickering B Refurbished (Bcf/year)



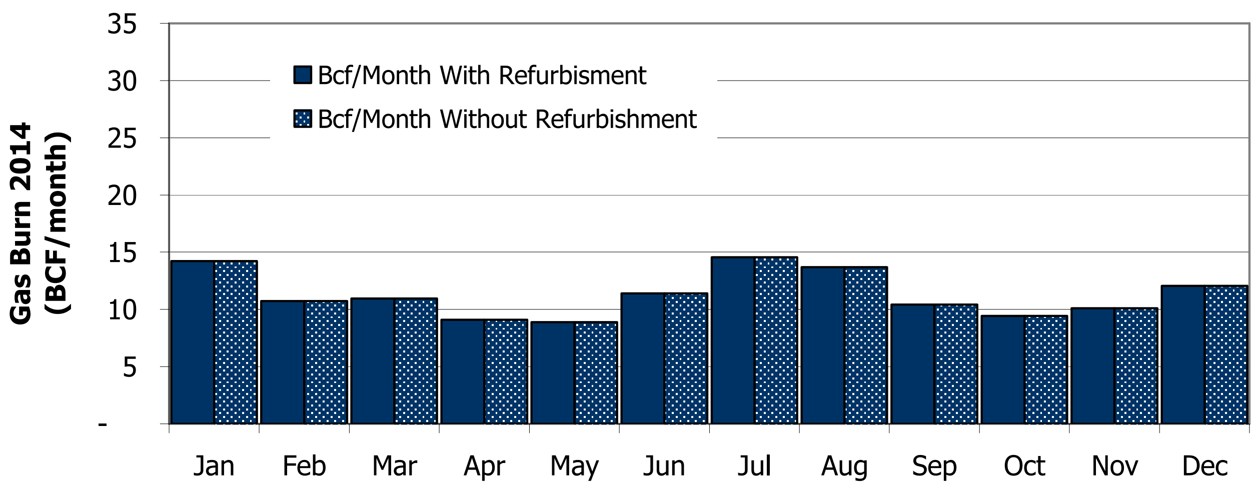
Source: OPA.

Natural gas consumption is seen to increase to a level of about 125 Bcf in 2011 to 2014, increasing to a level in excess of 200 Bcf for 2019 to 2021, then decreasing to a level of about 160 Bcf for the years 2022 to 2027. In 2017 and beyond there is a contribution from proxy gas, which would be reduced or eliminated should the proxy resources ultimately be provided by other than natural gas-fired generation.

The forecast natural gas consumption for electricity consumption is seen to peak at about 240 Bcf/year, which is nearly 25% of Ontario's current total consumption of about 1,000 Bcf per year.[15]

The seasonality of the natural gas consumption is shown in Figure 9 for 2014, a representative year of "normal" gas consumption, and in Figure 10 for 2019, representative of the highest consumption years in the Plan. The results for 2019 are illustrated for the two cases, with and without Pickering B refurbishment, the latter having somewhat higher gas consumption.

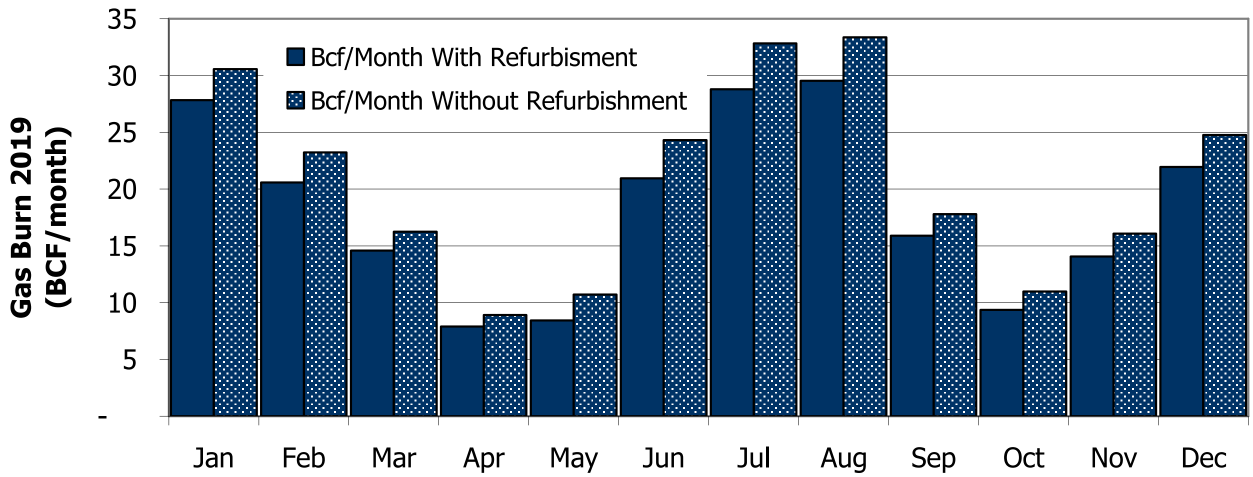
Figure 9: Seasonality of Natural Gas Consumption (Bcf/month) - 2014



Source: OPA.

[15] See NGEIR report, at http://www.oeb.gov.on.ca/documents/cases/EB-2005-0306/ngf_geinterface_report-211105.pdf. Ontario consumption (sales) is given by the Canadian Gas Association at http://www.cga.ca/publications/gasstats.htm.

Figure 10: Seasonality of Natural Gas Consumption (Bcf/month) - 2019



Source: OPA.

The results for 2014 show gas consumption to be substantially the same in the summer months of July and August and in the winter month of January. Gas prices tend to be highest in the winter. The average capacity factor ("ACF") of CCGT is 7% and that of SCGT is 0% in 2014. CHP has an ACF of 41%.

The results for 2019 show the same general pattern as for 2014, with comparable consumption in July, August and January. In 2019, the ACF of CCGT is 27% and that of SCGT is 6% for the case of Pickering B refurbished. For the case of Pickering B not refurbished, the ACFs are 32% for CCGT and 8% for SCGT. CHP again has an average capacity factor of 41%, for both cases.

Some stakeholders recommended the inclusion of natural gas fuel cells in the Plan. The OPA recognizes the potential for fuel cells as an energy conversion technology, with the possibility of significant technological and economic improvements occurring over the period of the Plan. Fuel cells using natural gas continue to evolve towards full-scale commercial operation, but are not yet well established for the size of unit that would make them alternatives to CCGT, or supplement them to a significant degree. Fuel cells are more likely to first develop as customer-owned, smaller-size facilities that supplement conservation, probably later in the planning horizon.[16] The OPA recognizes that technological advances will occur over the period of the Plan; however, given the uncertainty in the nature and timing of such advances, the IPSP adopts the approach of not speculating on specific technological advances, recognizing that when technological and economic developments are accepted commercially, they will be reflected appropriately in future Plans.

Q. What are the conditions necessary to achieve the Plan's gas-fired generation capacity and the associated timelines?

A. The necessary conditions are as follows:

- Sufficient gas infrastructure and commodity availability;
- Availability of critical project components and resources to develop, construct and operate facilities;
- Effective commercial arrangements;
- Timely project approvals and continuing financial viability of the projects; and
- Continued requirement for heat by accessible steam hosts, and the ability of the CHP projects to produce heat at a competitive price.

Q. How will the OPA monitor developments to evaluate the progress towards achieving the planned amount of gas-fired generation?

A. The OPA monitors, on an ongoing basis, the status and planned changes to the status of existing resources, the progress of committed resources, the progress of OPA-administered programs and contracts. This enables the OPA to make appropriate adjustments to its Plans and resource acquisitions over time.

[16] See Exhibit D-3-1.

4.0 ECONOMIC PRUDENCE AND COST EFFECTIVENESS

Q. How has the economic prudence and cost effectiveness of the IPSP's planned gas-fired resources been determined?

A. The OPA's three-step evaluation process was used to determine the role for natural gas-fired generation in the Plan. This process involved determining the requirement for planned natural gas-fired resources remaining after consideration of existing committed and planned conservation and non-gas supply resources, and existing and committed gas-fired resources. This remaining requirement for gas-fired resources was allocated among Lennox and planned CHP, SCGT and CCGT resources. Thus, gas-fired generation is only used to meet the residual requirement. This role for natural gas-fired generation reflects the desire to reduce air emissions and exposure to gas price volatility.

The natural gas-fired resources selected for inclusion in the plan are discussed below within this context.

Feasibility

The natural gas generation technologies of SCGT and CCGT are well established technically and commercially, and can be put in place relatively quickly. This is true to a lesser degree for CHP in the Ontario context.

CHP is a feasible resource. The maximum amount of CHP judged likely to develop over the period of the Plan, as assessed at this time, has been included in the IPSP. The expected amount of CHP is constrained by the limited potential for economic applications for the heat that is co-produced with the electricity.

In the NGEIR Report of November 2005, Ontario Energy Board staff concluded that delivery infrastructure would need to be upgraded, both in Ontario and upstream, but that such upgrades should follow established processes. These upgrades are currently under development.

Reliability

SCGT, CCGT and CHP are resources whose high operating reliability contributes to overall system reliability. Each of these technologies has proven to be reliable in terms of meeting its respective contribution to the system needs.

The total amount of planned new SCGT and CCGT gas fired generation was driven by the need to meet system resource adequacy requirements after other resources were taken into account.

Cost

Economic assessment was used to guide the selection of the relative amounts of SCGT and CCGT facilities to meet peaking and intermediate load requirements, respectively. The assessment involved establishing the breakeven points between viable alternatives. For purposes of meeting peak load requirements, the breakeven point between SCGT and CCGT gas-fired generation was considered.[17] For purposes of meeting intermediate load requirements, the upper limit on economic CCGT generation was determined by the breakeven point between CCGT and nuclear generation. Details of this assessment are contained at Exhibit D-3-1, Attachment 1.

Economic assessment was also used to establish that Lennox GS should be assumed to remain in operation throughout the period of the IPSP. This assessment determined that the cost of replacement capacity was greater that the cost of continuing to maintain and operate Lennox. Details of this assessment are contained in Exhibit D-8-1, Attachment 1.

Economic analysis was also used to determine the economic benefits of local generation in Northern York Region, Kitchener-Waterloo-Cambridge-Guelph, and Southwest GTA. Details of this analysis can be found in Exhibits E-5-1, E-5-2 and E-5-3.

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[17] This breakeven point occurs for the resources operating 14% of the hours in a year.

The additional 550 MW of gas-fired generation planned to be sited in the GTA reflects cost and reliability considerations. This generation will provide support to the GTA from a regional rather than local area perspective. Siting this generation close to a load centre as large as the GTA is cost effective because it reduces losses and provides additional voltage support that would otherwise require additional resources. Also, reliability will be enhanced, as a result of the increased generation levels internal to the GTA, leading to greater self-sufficiency and robustness against major system disturbances.

Flexibility

Natural gas-fired generation has a shorter lead-time requirement for development than other supply resources.

CCGT and SCGT have a high degree of geographic flexibility, limited mainly by the need to be in reasonably close proximity to natural gas supply infrastructure. This geographic flexibility means that these facilities are potentially an alternative to local area transmission reinforcement. As such, it contributes to the Plan's ability to respond to a range of future conditions. Three such projects are included in the Plan.

Gas-fired resources, by virtue of their characteristic flexibility and availability, are the principal source of flexibility for the Ontario system as a whole. The currently committed gas-fired resources will contribute to Ontario meeting reliability requirements while replacing coal-fired generation. They are also available to respond to uncertainties in assumptions, such as those relating to nuclear performance, higher load growth, delays in acquiring new resources, and nuclear refurbishment decisions.

While the Plan presents specific amounts, timing and types of natural gas-fired resources, it is useful to consider these resources as part of a generic natural gas resource portfolio that will become progressively transformed into specific resources at the times in the future when specific resource decisions are made. This generic portfolio also includes the resources in the Plan (NUG, CCGT, SCGT, Lennox), and adding additional capacity at existing generation sites. It also includes the option of converting coal-fired gas units at Nanticoke to natural gas, which is not recommended at this time, but nevertheless remains an option.

SCGT also provides a high degree of operating flexibility, for example, to keep total system generation and demand in balance in real time.

Environmental Performance

Natural gas-fired generation, if used extensively, has high air emissions (in relation to those of wind, hydroelectric and nuclear resources). On a unit of production basis, SCGT has poorer performance than that of CCGT and CHP. Natural gas-fired generation also produces significant amounts of nitrogen oxides (NOx) and must meet NOx emission standards.

These considerations are reflected in the role accorded natural gas-fired resources in the Plan, namely the Plan uses the value of natural gas-fired resources in providing capacity and flexibility, while limiting energy production to reduce costs, cost exposure, and air emissions.

Societal Acceptance

The role of natural gas-fired generation in the IPSP recognizes the conflicting views among stakeholders with respect to its use. Natural gas is essential to meeting the requirement for timely replacement of coal-fired resources and to providing short lead-time responses to changed assumptions respecting other resources. In local areas, it may be selected over transmission options on acceptability grounds. To the extent practical it will be used to meet capacity requirements with limited energy production and associated air emissions. In general, the role of natural gas is incorporated in the OPA's determination of what constitutes a high value use of the fuel, namely, that it be used where it has a material advantage over alternatives, or is the only feasible choice.

Q. What capital investment is associated with the planned gas-fired resources?

A. The capital investment (2007 $ millions) associated with the planned gas-fired resources are shown in the following table:

Table 13: Capital Investment of the Planned Gas-Fired Resources

$ (2007) Billions	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
With Refurbishment	-	-	0.12	0.85	0.73	0.92	0.19	0.30	-	0.09	0.09	-	-	-	-	-	-	-	0.14	0.14
No Refurbishment	-	-	0.12	0.85	0.73	0.92	0.19	0.30	0.11	0.20	0.13	0.04	-	-	-	-	-	-	0.04	0.04

Source: OPA.

DISCUSSION OF THE ONGOING REQUIREMENT FOR THE AVAILABILITY OF THE LENNOX GENERATING STATION AND THE COST EFFECTIVENESS OF ALTERNATIVES

1.0 INTRODUCTION

Lennox Generating Station ("Lennox GS" or "Lennox") is a four-unit fossil generating station with an installed capacity of 2,140 MW. Located near Kingston, Ontario, it was commissioned as an oil-fired facility in 1976, and was converted to dual oil and natural gas firing facility in the late 1990s. Lennox is owned by OPG and is operated as a peaking resource.

In July 2005, OPG issued a request to the IESO to deregister Lennox. The request was rejected for reliability reasons. A reliability must-run (RMR) agreement was subsequently negotiated with OPG for a one year term for the period October 2005 to September 30, 2006[1]. The agreement was approved by the Ontario Energy Board.

On March 29, 2006 OPG indicated that it was prepared to negotiate a second RMR agreement unless the IESO determined that Lennox was not required for reliability and could be de-registered. A second RMR agreement was subsequently approved by the OEB for another one year term for the period October 2006 to September 30, 2007[2].

The RMR agreement costs approximately $62 million per year and is intended to cover OPG's fixed and variable costs for Lennox (net of energy revenues). The RMR agreement includes an obligation on OPG to offer into the IESO-administered markets for the "maximum amount of energy and operating reserve from Lennox in a commercially reasonable manner and in accordance with stated performance standards".

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[1] The RMR agreement was approved by the OEB on March 13, 2006.
[2] The second RMR agreement was approved by the OEB on January 22, 2007

In its decision to approve the second RMR agreement, the OEB noted that “at a net cost of roughly $60 million per year, the Lennox RMR Contract is a significant cost borne by electricity consumers”. The OEB went on to state that it is “concerned about the possibility of being asked in the future to routinely approve one-year RMR arrangements for Lennox without any evidence of whether there are any cost-effective alternatives that should be pursued”. The OEB concluded that it anticipates “in its IPSP filing in 2007, the OPA will provide an analysis of the reliability issues in Eastern Ontario for the next 20 years as well as an economic analysis that shows the most cost effective way to deal with the identified reliability issues”.

This attachment presents the OPA’s findings with respect to:

- the ongoing requirement for Lennox or its equivalent capacity; and
- whether Lennox, under an RMR contract or other mechanism, continues to provide value to Ontario in comparison to other generation alternatives.

It is concluded here that there is an ongoing requirement for Lennox or its equivalent and that Lennox is the more cost effective option compared to a new simple cycle or combined cycle gas-fired generator. It also concludes that while the requirement for Lennox may extend into the medium- and long-term, any potential financial arrangement over Lennox would need to preserve flexibility as to the duration of the arrangement. This would be particularly relevant in view of long-term uncertainty and the ability to take advantage of emerging opportunities.

2.0 ASSESSMENT OF THE REQUIREMENT

In assessing the requirement for Lennox for the period October 2006 to September 2007, the IESO observed the following:

> [R]eliability conditions in the Eastern Ontario and Toronto areas continue to require the availability of all four units at Lennox in 2007 – largely due to forecasted load growth, concerns for Ottawa area supply reliability, security concerns in case the new Goreway

GS is not available for the summer 2007, scheduled generation outages in northern Ontario and overall system reserve requirements[3].

It is expected that, over time, the factors identified above will be addressed by new resource developments planned around Ottawa and in the Greater Toronto Area (the "GTA"). For example, it is expected that the requirement for Lennox to address security concerns in the GTA will be mitigated as the Goreway, Portlands and Halton Hills generation projects enter service. Likewise, it is expected that the development of the new 1,250 MW intertie with Hydro Québec will relieve the need for Lennox to support Ottawa area supply reliability. The IESO continues to assess these factors and their impact on the need for Lennox as a local area reliability resource.

While the local area reliability requirements for Lennox are expected to be addressed over time with the implementation of the above and other initiatives, the requirement for the entirety of the Lennox generating station or its equivalent capacity persists for the purpose of supporting overall resource adequacy in Ontario (i.e., the ability to meet demand and planning reserve requirements).

3.0 ECONOMIC ANALYSIS

The approach to the economic analysis assumes that the capacity required to provide the overall resource adequacy is to be supplied by a facility (or facilities) with an equivalent capacity and similar technical characteristics as Lennox currently provides. In essence, the economic analysis presents a relative comparison of Lennox and a new-build generation asset.

In order to evaluate the cost of replacing Lennox with a new generation asset, the cost of a replacement asset that has similar operating characteristics as Lennox was estimated. Lennox, being a dual fuelled conventional boiler steam plant, is characterized by the following technical features, which are listed below:

[3] IESO in EB-2006-0205, Submissions of the Independent Electricity System Operator. November 29, 2006

- Ramping capability;
- Low turn-down ratio and part load operation;
- Dispatchability; and
- Dual Fuel capability

There are two types of generating technologies which can provide the characteristics above, namely, simple cycle gas turbines (“SCGT”) and combined cycle gas turbines (“CCGT”). Replacement with a similar conventional boiler steam plant was discounted as an option due to the high capital cost and lower efficiency in comparison to SCGT or CCGT.

As outlined in Table 1, the total cost of operating Lennox under the current RMR agreement is forecast to be $101.7 million in 2006 to 2007. The total market revenue of Lennox for 2006 to 2007 is $40.1 million. The 2006 to 2007 net cost, being the difference between the total cost and the total market revenue, is therefore $62 million. In this analysis, this value is referred to as the “Lennox Out-of-Market Cost”. Under the RMR agreement, the Lennox Out-of-Market Cost is paid by ratepayers through mechanisms other than the Wholesale Electricity Market.

It is assumed that the current cost of Lennox as identified in the OEB submittal is sufficient to enable Lennox to continue operating as a peak capacity resource. In other words, it is assumed that the net cost is sufficient for Lennox to meet its fixed costs, including any ongoing capital or major maintenance expenditures. This assumption is supported by information received from OPG and internal resources which indicate that Lennox would not require any major capital expenditures in the near-term and potentially not for the next 20 years. The use of natural gas at the facility combined with the relatively low number of operating hours result in minimal annual repair and maintenance costs.

Table 1: Forecast and Actual Costs and Revenues for Lennox

$ millions *12 months ended September 30*		2005-2006		2006-2007
		Forecast	Actual	Forecast
Costs				
Fuel		$ 29.6	$ 52.1	$ 43.2
OM&A		51.8	50.3	51.3
IESO market costs		-	6.4	1.8
Working capital financing		3.0	4.7	4.0
		84.4	113.5	100.3
Margin amount		1.3	1.3	1.4
	[A]	85.7	114.8	101.7
Revenue				
Total		24.8	59.6	42.2
Retained by OPG (5%)		- 1.2	- 3.0	- 2.1
	[B]	23.6	56.6	40.1
Net cost	[A]-[B]	$ 62.1	$ 58.2	$ 61.6

Source: OEB

For the sole purpose of this analysis, a contract structure similar to the OPA's Clean Energy Supply ("CES") contracts was used. The CES contract structure is a contract for differences ("CFD") whereby a generator establishes a Net Revenue Requirement ("NRR"), in $/MW-month, that is required to meet all fixed operating and maintenance costs as well as to pay off capital expenditures and financing costs. The generator is deemed to generate in the market when its variable operating cost (being the sum of fuel cost and variable operating cost) is less than the Hourly Ontario Energy Price ("HOEP"). The net market revenue equals the gross electricity market revenue less the variable energy cost of producing electricity. The financial settlement with the generator is the difference between the NRR multiplied by the capacity and the net market revenue it is deemed to produce. If the difference between NRR multiplied by the capacity and the net market revenue is positive, the generator receives a payment; if the difference is negative the generator owes a payment. This difference can be referred to, for the purposes of this analysis, as the "CES Out-of-Market Cost". Cost estimates for the SCGT and CCGT alternatives are summarized in Table 2.

These costs are planning estimates used for comparative purposes. They may vary in practice and over time.

Table 2: Key Assumptions for Modeling Comparator Plants

	Capacity	Capital Cost	Heat Rate	O&M	Start-up Cost	Net Revenue Requirement
	MW	$/kW	Btu/kWh	$/MWh	MMBtu/Start	$/(MW*month)
SCGT	2,140	665	9,500	3.50	700	8,500
CCGT	2,140	924	7,000	2.75	800	11,900

Source: OPA, Navigant Consulting

Overall costs of an SCGT or CCGT facility are the sum of the fixed costs and variable energy costs. Fixed costs include capital costs, fixed maintenance costs, and labour costs. The variable energy cost consists mainly of the gas consumed by the facility, and is a function of gas price, heat rate and capacity factor.

Lennox has a relatively low fixed cost compared to a new SCGT or CCGT facility of the same size. This is seen in Figure 2, where the annual fixed costs of a new SCGT or CCGT would be in the realm of $200-300 million per year[4], compared to Lennox's fixed cost of about $60 million per year, as shown in Table 1. Higher fixed costs of a new SCGT or CCGT facility would be largely a result of higher capital carrying costs, as Lennox is fully depreciated.

A model was developed to assess the SCGT and CCGT options. The model assumed that the SCGT and CCGT plants operated according to the deemed dispatch incentives in the CES contracts. The model used actual HOEP, 3-hour-, 2-hour- and 1-hour-ahead pre-dispatch prices, and Dawn Hub daily gas prices as inputs. The model is a modified version of the settlement model for the financial settlement of the majority of gas-fired generation CES contracts that the OPA administers. The settlement model assumes operation of a gas-fired plant based on the electricity and gas market conditions, and determines the hours in which operation of the plant is economically viable. The CES contract conditions provide a gas-fired generator financial incentive to operate in the hours

[4] i.e. Monthly Net Revenue Requirement multiplied by 12 months per year multiplied by 2,140 MW

when operation is economically viable. Thus, the settlement model reflects the predicted operation of a gas-fired plant under contract with the OPA using the CES contract structure. The operation of the SCGT and CCGT options were evaluated for the years 2005 and 2006. These years were considered in the evaluation because RMR contracts for Lennox existed in these years. As such, the net out-of-market costs calculated by the model and the RMR contract could be compared in similar gas and electricity market conditions.

4.0 FINDINGS

The results of the analysis are summarized below in Table 3. The values in Table 3 are the Out-of-Market Costs that would have been paid to the comparator SCGT and CCGT generators in 2005 and 2006. The values cited for Lennox in Table 3 are the actual Out-of-Market cost paid to Lennox under the RMR agreement in 2005 and the forecast compensation that will be paid in 2006 under the current RMR contract.

Table 3: Net Out of Market Costs of Comparator Plants 2005 & 2006 ($Millions)

	Year	
	2005	**2006**
SCGT	$132	$237
CCGT	$154	$196
Lennox	$58*	$62**

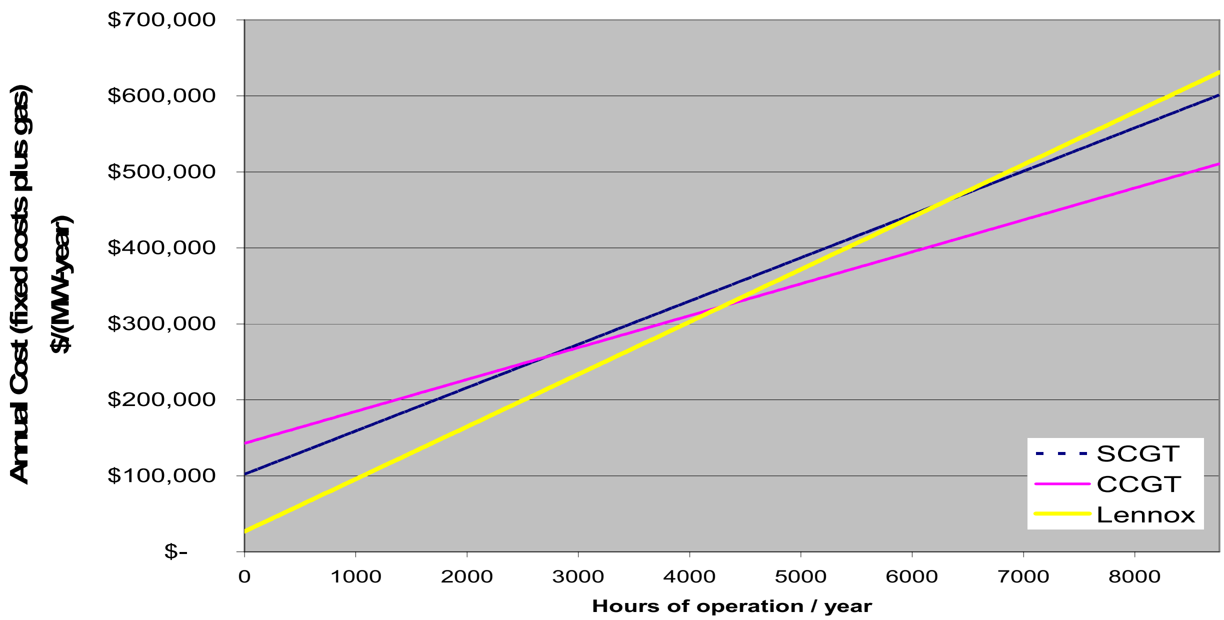
Source: OPA
*Actual cost for Oct. 2005- Sept. 2006
**Estimated cost for Oct. 2006- Sept. 2007

It is seen that in 2005, the Out-of-Market cost paid to the comparator SCGT or CCGT options would have been between two and almost three times greater than the compensation required for Lennox. In 2006, the Out-of-Market cost paid to the SCGT or CCGT options would have been between three and four times the cost of the existing RMR agreement with Lennox. The above results therefore suggest that the Lennox facility represents better value in terms of providing equivalent capacity when evaluated against new-build SCGT and CCGT options. The net Out-of-Market costs fluctuate year to year for both the SCGT and the CCGT due to changing gas and electricity market conditions. In years with lower wholesale electricity prices and higher gas prices the net Out-of-Market cost will typically be higher since a generation facility will typically operate less (because the price paid for electricity is less than the price it costs to produce the electricity in a larger number of hours). When electricity prices are higher and gas prices are lower, a generating facility will typically operate more (because wholesale electricity prices are higher than the cost of producing the electricity).

While the above results are specifically for the years 2005 and 2006, it is estimated that Lennox will continue to be cost effective in future years. As discussed above, this is due to its relatively low fixed cost and expected low capacity factor.

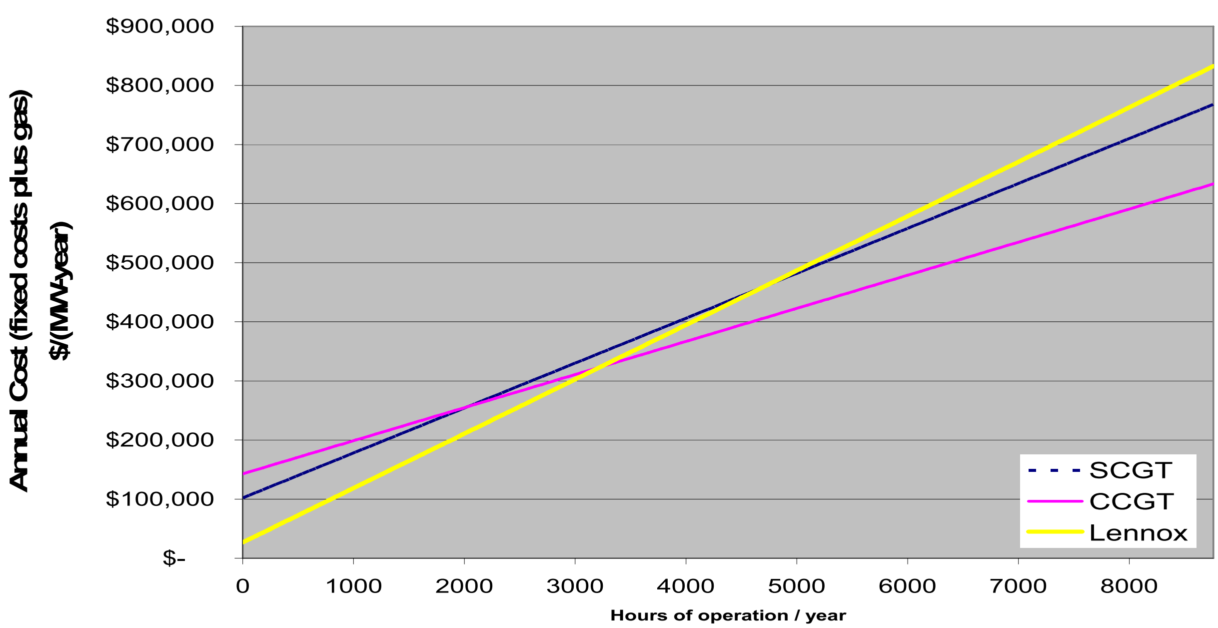
As illustrated in Figures 1 through 3, Lennox is the lower cost option under various gas price scenarios provided that the capacity factor of Lennox does not exceed about 30% to 45%, depending on the gas price. It is expected that Lennox's capacity factor will remain well below 30% in the future, typical of a peaking plant. Lennox has relatively high variable energy costs on a unit basis (owing to a higher heat rate), but due to the relatively low number of hours that Lennox would be expected to run in a given year, the total energy costs would remain relatively low. The combination of low total energy costs due to a low capacity factor and low fixed costs make Lennox a less expensive alternative than a new build SCGT or CCGT.

Figure 1: Annual Cost: Lennox vs. SCGT & CCGT at $6/MMBTU Gas Cost



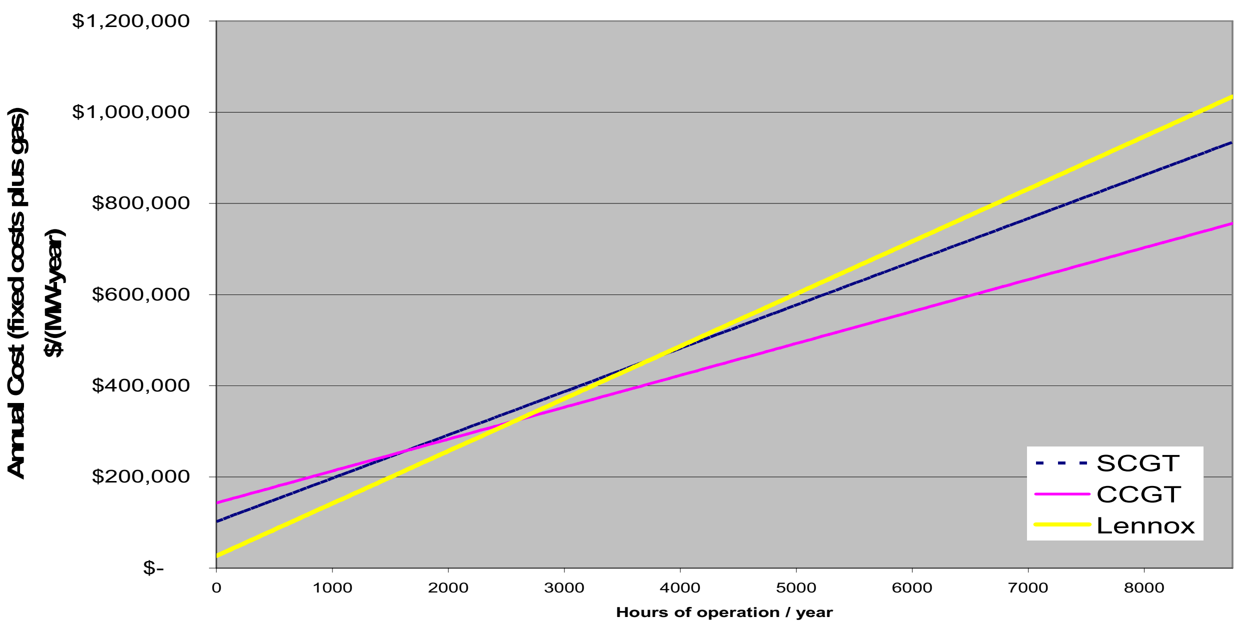
Source: OPA

Figure 2: Annual Cost: Lennox vs. SCGT & CCGT at $8/MMBTU Gas Cost



Source: OPA

Figure 3: Annual Cost: Lennox vs. SCGT & CCGT at $10/MMBTU Gas Cost



Source: OPA

5.0 CONCLUSION

The above discussion identifies an ongoing requirement for Lennox or its equivalent for the support of overall resource adequacy in Ontario. In comparing the cost effectiveness of Lennox relative to alternative options, it is seen that replacing the Lennox GS with a new SCGT or CCGT plant would have cost between two to four times more per year in 2005 and 2006 than the level of compensation currently being provided to Lennox under the existing Reliability Must Run arrangement. It is also seen that Lennox would continue to be the lower cost option in future years, subject to a relatively low utilization typical of a peaking resource. It is expected that the role of Lennox in the future would continue to be a peaking resource.

The requirement for Lennox or its equivalent has been estimated to persist throughout the mid-term, and potentially into and throughout the long-term. In the longer-term, the requirement may be reduced or eliminated depending on the cumulative success of initiatives implemented prior to then (e.g., Conservation, renewables, gas, nuclear), as well as on the outlook for future initiatives (e.g., northern waterpower). Greater than expected success in implementation of new resources (i.e., in terms of amounts and timing) can also reduce the requirement. For example, greater or accelerated success in the uptake of demand response may present a cost effective and feasible alternative.

The IESO is unlikely to require Lennox for local area requirements for an indefinite period of time and will therefore eventually be unable to secure Lennox's capacity under ongoing RMR contracts in accordance with the Market Rules. Through its efforts to deregister Lennox, OPG has indicated that without a financial support mechanism, Lennox would be shut-down as market revenues are insufficient to meet its costs.

If a financial arrangement were contemplated to secure the ongoing availability of Lennox outside of the RMR mechanism, the term of the potential arrangement could provide for the flexibility to adapt to changing circumstances in the medium- and long-term in recognition of the uncertainties inherent in forecasting over long periods of time.