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".

[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**

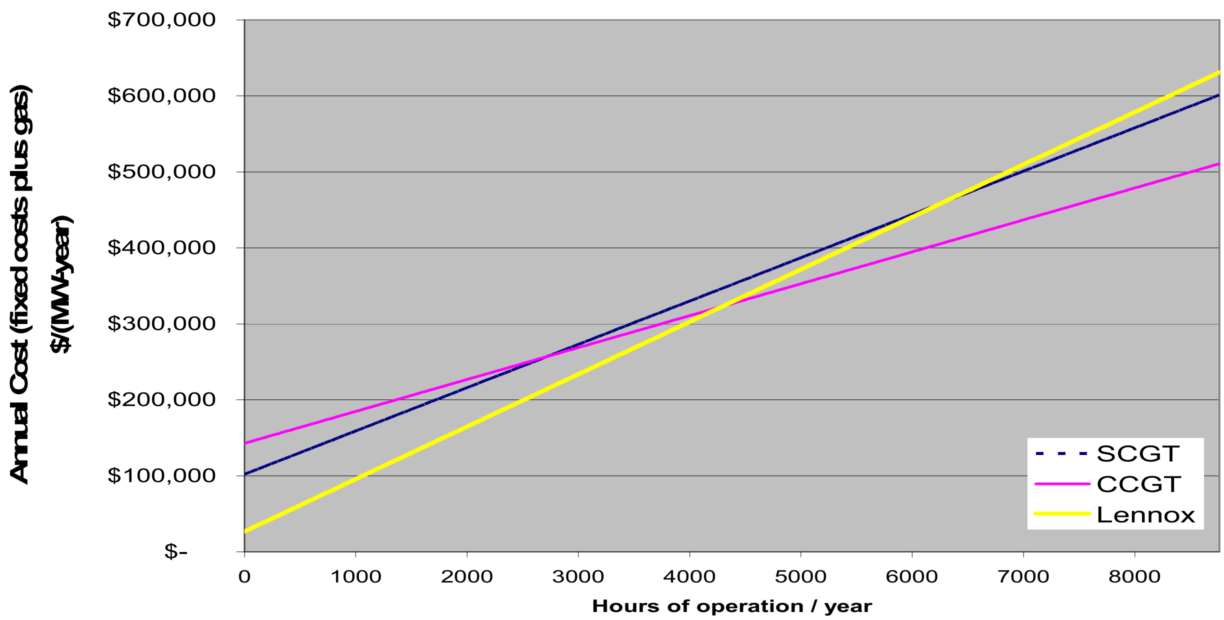
Source: OPA
*Actual cost for Oct. 2005- Sept. 2006
**Estimated cost for Oct. 2006- Sept. 2007

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.

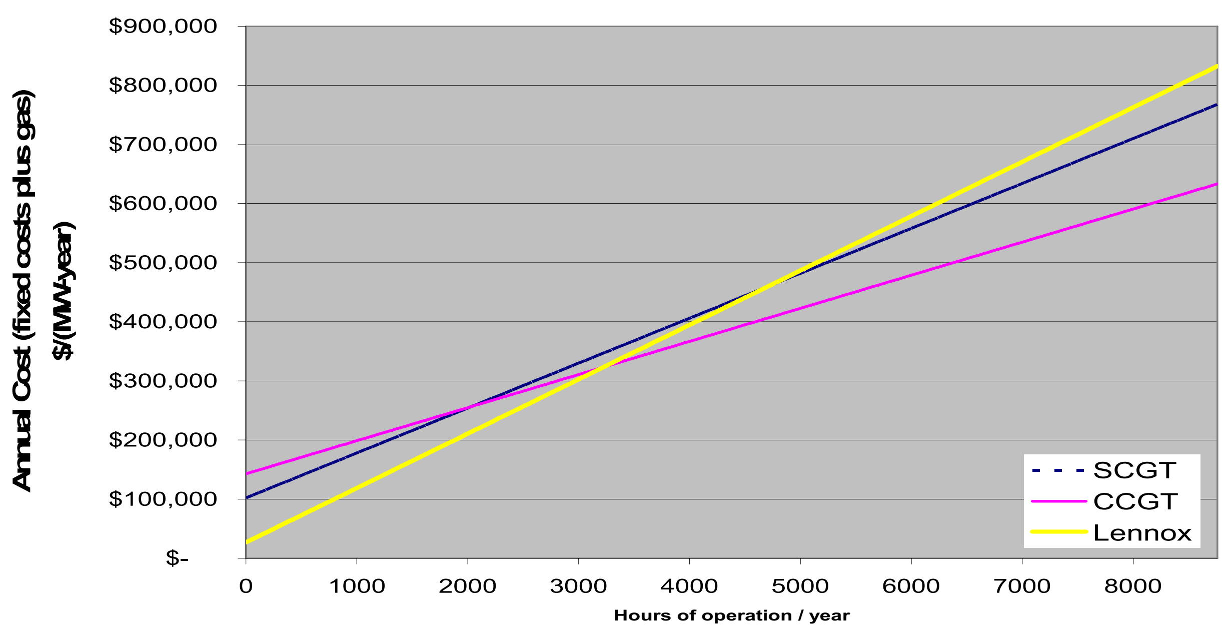
As illustrated in Figures 1 through 3, Lennox is the lower cost option under various gas price scenarios provided that the capacity factor of Lennox does not exceed about 30% to 45%, depending on the gas price. It is expected that Lennox's capacity factor will remain well below 30% in the future, typical 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



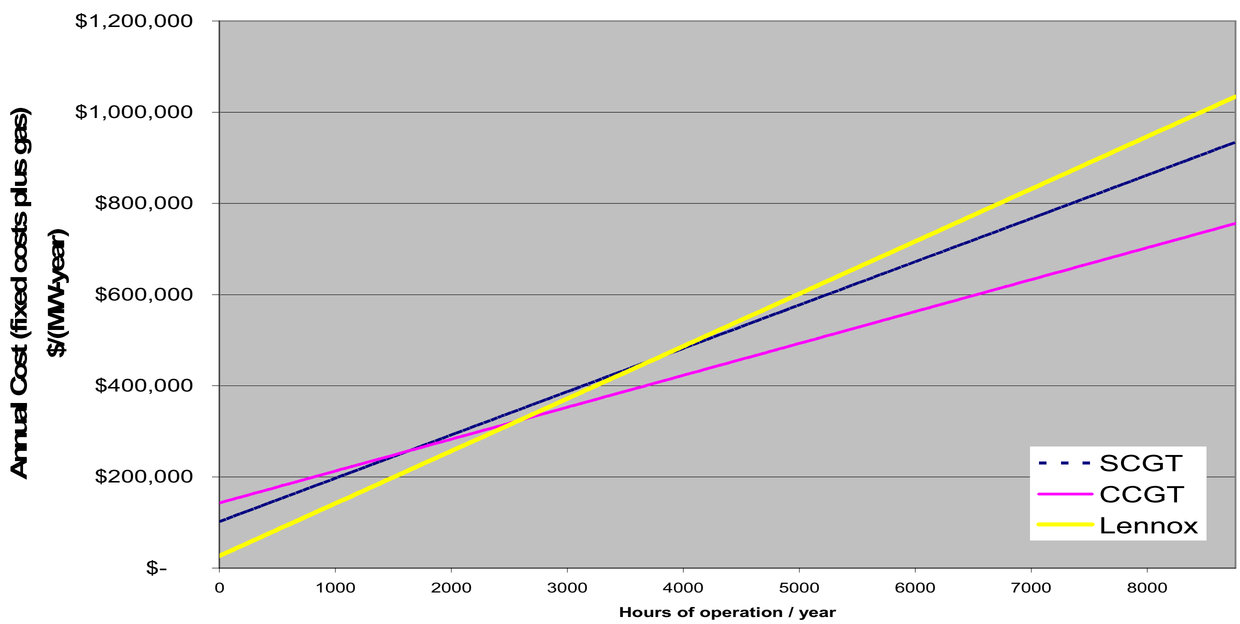
Source: OPA

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.