Exhibit G

Preliminary Conclusions Regarding the Role of Peaking Capacity in Ontario

London Economics International LLC

August 29, 2005

Preliminary conclusions regarding the role of peaking capacity in Ontario's future supply mix

prepared by London Economics International LLC

August 29, 2005

Using Independent Electricity System Operator (IESO) projections from IESO's 10 Year Outlook and applying our proprietary models of the Ontario electricity market, London Economics International LLC (LEI) has identified a need for a minimum of 339 MW of simple cycle gas turbine peaking capacity over the next ten years, including 206 MW in 2008 and 133 MW in 2014. This level of peaking capacity addition is justified based on the gestation period for new peaking capacity relative to need, and the ability to add such capacity in discrete amounts to conform to system requirements. Additional peaking capacity above the recommended amount could be justified based on need for insurance against super-peak prices. Where possible, planners may want to encourage simple cycle configurations which allow for subsequent conversion to combined cycle operation. Investments in demand response may also be cost-effective. Given that we have identified a potential need for peaking capacity of 339 MW, it would be rational to site such capacity in areas of transmission congestion, such as the York region.

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1 Overview

London Economics International LLC (LEI) was commissioned by the Ontario Power Authority (OPA) to provide insight into the question of the appropriate mix of peaking and baseload capacity additions in Ontario over a ten year forecast horizon. LEI relied on data supplied by the Ontario Independent Electricity System Operator (IESO) for key assumptions regarding system composition and future need.

To determine the appropriate proportion of peaking power in the overall supply mix, we followed a four step process. The steps are as follows:

- using IESO data regarding expected load growth, desired internal reserve margins, and entry and retirements, we identified years in which reserve margins are expected to fall below the required threshold and calculated the supply deficit;

- we then created a range of configurations of peaking power (represented by simple cycle gas turbines (SCGTs)) and baseload (represented as combined cycle gas turbines (CCGTs) entry, and tested each using our proprietary dispatch model of the Ontario market to calculate the cost to load under each entry scenario;

- once the optimal entry profile was identified in the basecase, we then tested the profile against six sensitivities, which were based on variations in hydrology, nuclear availability, and weather;

- these sensitivities were followed by an exploration of the value of peaking plants as insurance against super-peak prices, in the event that actual outcomes deviate from expected outcomes.

We describe each of these steps in greater detail in the sections below.

2 Determining aggregate need

We determined aggregate need for new capacity by using the IESO forecast of peak load growth for the next ten years as shown in *IESO's 10 Year Outlook*. We then compared the progression of peak load for the next decade to expected internal system capacity, using the up-to-date internal generating resources adjusted for forced outage rate (FOR) as a baseline.

We accepted as given the current schedule with regards to the shut down of the coal stations in Ontario, timelines for nuclear refurbishment, online dates for winners of the recent requests for proposals (RFPs), and announcements regarding Ontario Power Generation (OPG) investments. The resulting schedule of entry and exit provided us with a perspective with regards to current expected available internal resources in Ontario over the next ten years.

Next, we reviewed IESO statements regarding required internal reserve margins in Ontario in order to meet reliability expectations. IESO notes that it believes a 15% internal reserve margin is required to maintain reliable electricity service in the province[1]. Therefore, we took expected peak load, added on the reliability-determined reserve margin, and compared the total to the expected available system resources in each year. Over the next ten years, the results of this analysis show that upwards of 4,097 MW of new capacity (FOR-adjusted) may be required. The graph and table below depict the results.

Figure 1. Projected peak demand and FOR-adjusted capacity in Ontario

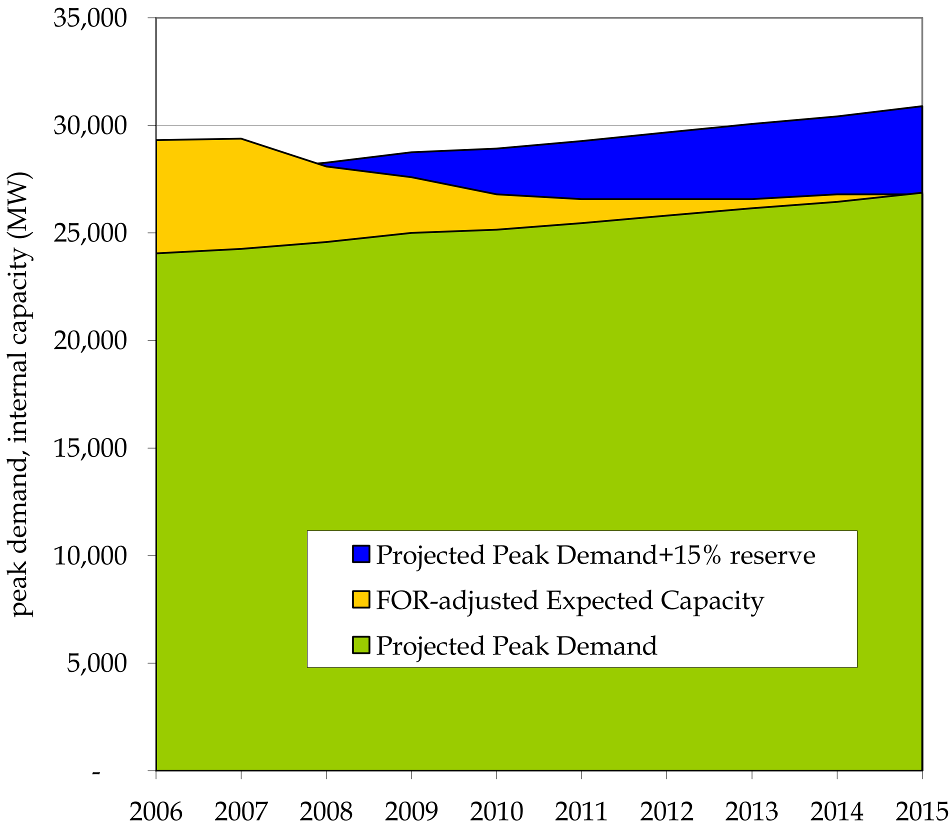


Figure 2. Cumulative and incremental new entry (FOR-adjusted) (MW)

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
cumulative new entry to meet 15% reserve			181	1,167	2,132	2,707	3,108	3,503	3,621	4,097
incremental new entry to meet 15% reserve			181	986	965	575	401	395	117	476

Note: The capacities above are FOR-adjusted. Therefore, the 181 MW and 117 MW of new entry capacity will translate into 206 MW and 133 MW of peaking capacity in 2008 and 2012 given the 12% forced outage rate, respectively. For baseload, we assume a forced outage rate of 2%.

[1] Sources: *IESO's 10-Year Outlook*: an assessment of the adequacy of generation and transmission facilities to meet future electricity needs in Ontario.

3 Identifying optimal entry profile

Having identified the aggregate need, we then turn to the question of what might be the most appropriate resources to meet that need. To do so, we deploy a cost-to-load approach to compare the impact on final Ontario consumers, examined across several different new supply portfolios.

3.1 cost-to-load approach

The cost-to-load approach enables us to compare the net present value of the electricity supplied from various supply portfolios, and to choose the supply portfolio which minimizes cost to final consumers over the specified forecast horizon. This process has several steps, as set forth below.

- **CES style contracts assumed:** We first assume that new supply will be brought on line over the next ten years through RFP processes similar to the CES contracts recently issued.

- **Maximum capacity payments determined:** Next, we examine the all-in revenue requirements of SCGTs and CCGTs in Ontario, assuming a zero percent load factor. The assumed all-in revenue requirement is shown in Appendix B. This calculation determines the maximum capacity payment which the OPA (and ultimately consumers) would be required to pay.

- **Plant running regimes projected:** In turn, we then run our least cost dispatch model to determine how often each type of plant is likely to run, and the margins it would earn in the market. We subtract margins earned in the market from the maximum capacity payment to determine net capacity payments in any single year.

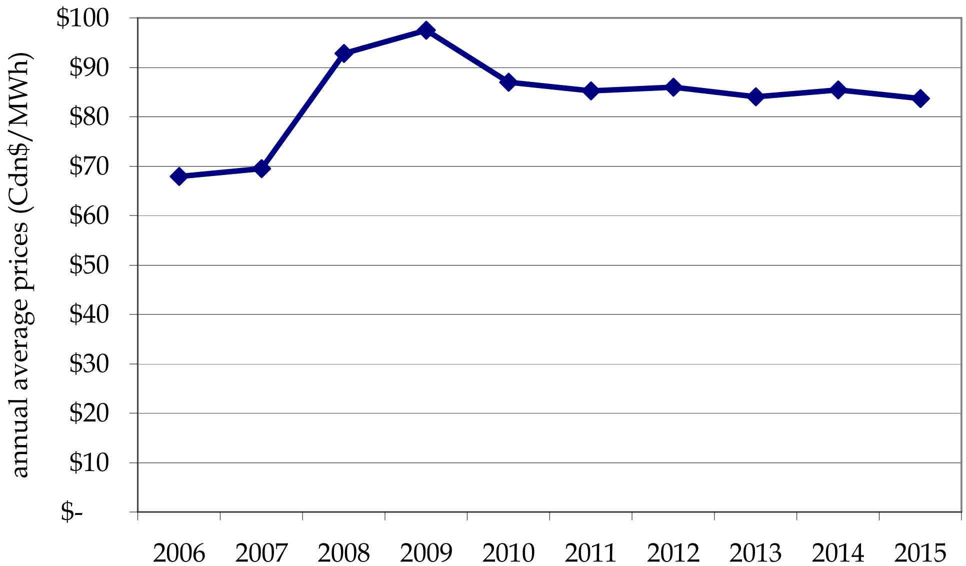
- **Energy costs calculated:** To determine cost to load, we then take total volumes sold in the each hour in a year times the price in the relevant hour, and sum the energy costs in each hour; we then add the net capacity payments required.

- **NPV derived:** We take the total annual cost to load in each year, and discount back to the present at a 10% discount rate to determine the net present value of the electricity supplied; the entry scenario producing the lowest cost to load is then selected as being the most economic.

3.2 base case analysis

We deployed our proprietary least cost dispatch model, POOLMOD, to provide forward energy prices under a range of entry scenarios. POOLMOD provides annual hourly price profiles using a detailed dispatch algorithm which takes into account fuel costs, efficiencies, hydrology, dynamic constraints, maintenance schedules, forced outage rates, and other relevant parameters. We utilized hourly demand forecasts prepared using IESO load growth projections, current forward fuel prices adjusted for delivery margins, entry and exit profiles consistent with those used by IESO and in accordance with announced government policy, and assumed that all of the plants currently contracted for in the Ministry of Energy processes would come on line. Details of our assumptions can be found in Appendix A. Over the near term, our modeling results are consistent with published forward prices.

Figure 3. Annual average prices under optimal entry configuration



3.3 new supply portfolios

As noted, over the next ten years the aggregate need in Ontario appears to be 4,097 MW (FOR-adjusted). To test which configuration of peaking versus baseload plant would be optimal, we examined 36 alternative new supply portfolios, ranging from entirely baseload (except in cases where unit sizes would be too small or the project gestation period too short), to entirely peaking. Detail of 36 alternative new entry portfolios can be found in Appendix C. Effectively, the analysis is designed to determine at what point the tradeoff between lower energy costs conveyed by CCGTs is offset by their higher capital costs relative to SCGTs.

We numbered the scenarios we modeled from #1 to #36. The figure below shows the resulting cost-to-load in three of our tested scenarios: an all peaking scenario (#36), a scenario in which 50%~75% of the capacity added is baseload and 50%~25% is peaking (#23), and a scenario in which baseload is added in all cases in which unit size needs and gestation periods allowed (#1). As the graphic shows, the optimal entry profile was #1 which deployed baseload resources to provide a large proportion of needed supply. This results in 206 MW of peaking units being installed in 2008, and 133 MW of peaking units being installed in 2014. As we move from #1 to #23, the CCGTs' % in the entry profile decreases from 93%[2] to 54 %, resulting in approximately 4% increase in cost of load. Furthermore, as we move from #23 to #36, the CCGTs' % in the entry profile decreases from 54% to 0 %, resulting in approximately 5% increase in cost of load.

[2] Please note that the % here only reflects CCGT entry as a percentage of total new entry needed (i.e. 4,097 MW). It, however, doesn't reflect the timing of new entry.

Figure 4. NPV of 10 years cost of load under three selected entry profiles[3]

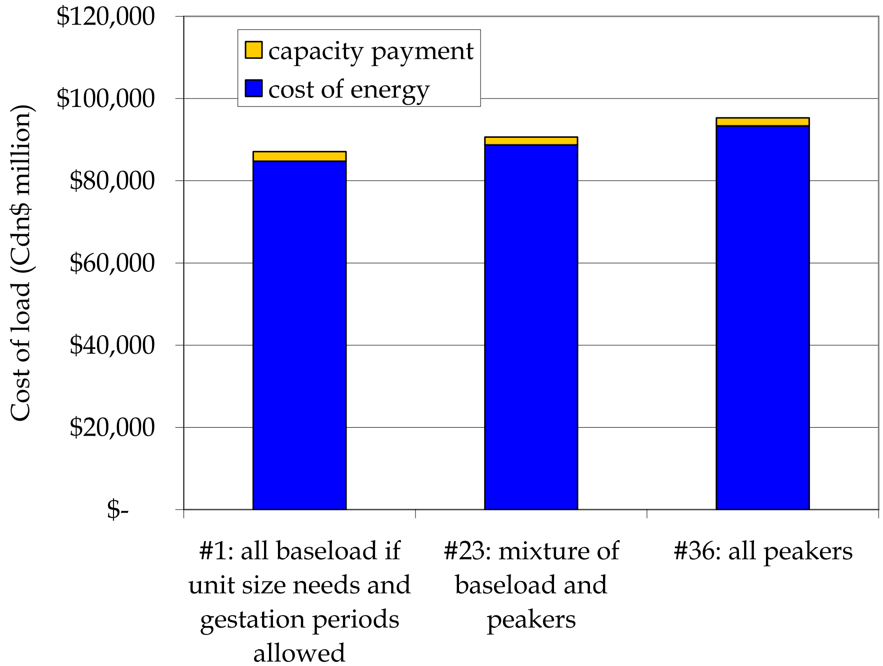


Figure 5. Three selected entry profiles

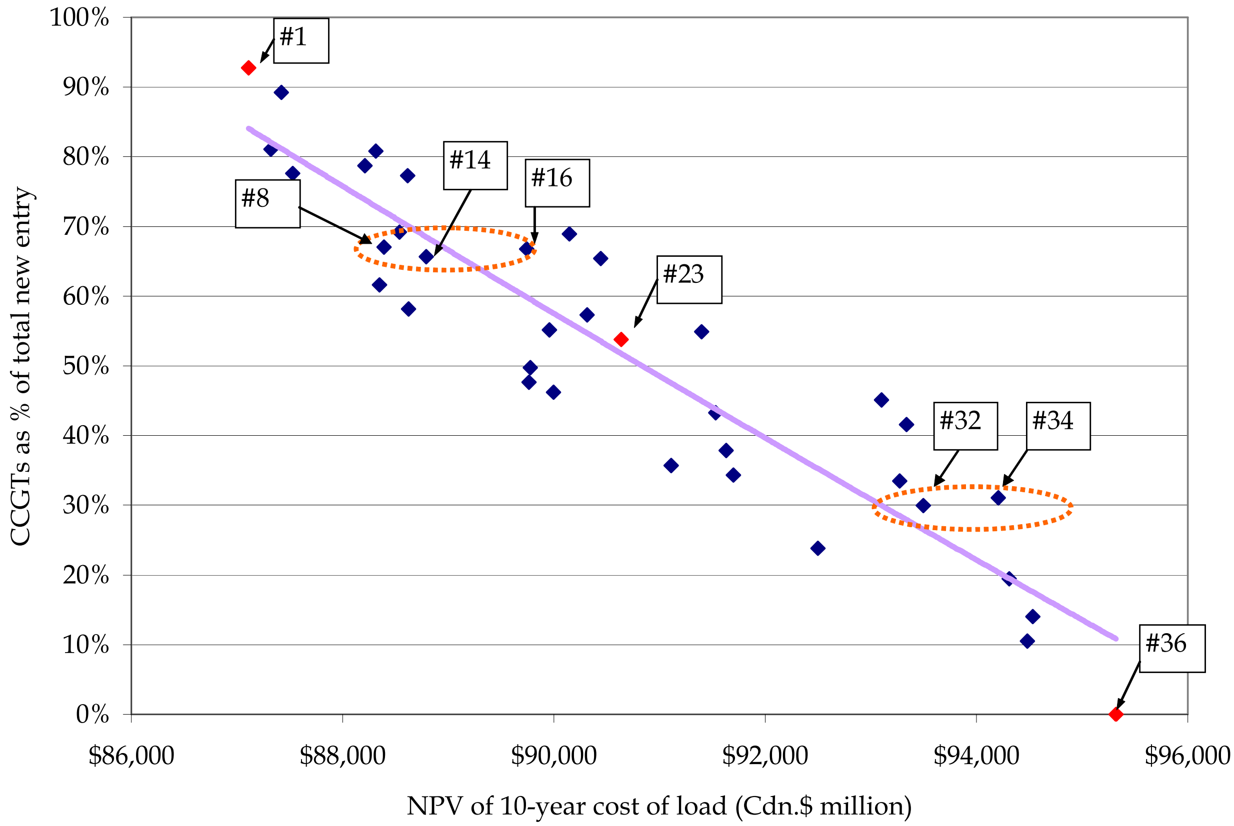
	2008	2009	2010	2011	2012	2013	2014	2015
#1: all baseload if unit size needs and gestation periods allowed								
% of CCGT in the new entry profile	0%	100%	100%	100%	100%	100%	0%	100%
CCGT new entry (ICAP, MW)	-	1,006	985	586	410	403	-	486
SCGT new entry (ICAP, MW)	206	-	-	-	-	-	133	-
#23: mixture of baseload and peakers								
% of CCGT in the new entry profile	0%	50%	50%	75%	100%	100%	0%	0%
CCGT new entry (ICAP, MW)	-	503	492	440	410	403	-	-
SCGT new entry (ICAP, MW)	206	560	548	163	-	-	133	541
#36: all peakers								
% of CCGT in the new entry profile	0%	0%	0%	0%	0%	0%	0%	0%
CCGT new entry (ICAP, MW)	-	-	-	-	-	-	-	-
SCGT new entry (ICAP, MW)	206	1,121	1,096	653	456	449	133	541

We can draw a preliminary conclusion that there is a negative correlation between the share of CCGTs in the new entry fuel mix and the cost of load (see figure below). Again, here we want to reiterate that the % here only reflects CCGT entry as a percentage of total new entry needed (i.e. 4,097 MW). It, however, doesn't reflect the timing of new entry. For example, #32 and #34 have

[3] NPV of 10 year cost of load for all 36 alternative new entry portfolios can be found in Appendix C.

similar CCGTs mix in their new entry profile, approximately 30%. A delayed CCGT new entry pattern in #34 (CCGT in service after 2012) results in higher cost of load comparing to #32 (CCGT in service after 2011). The same situation can be found in case #8, #14 and #16. (Details for each case can be found in Figure 18)

Figure 6. Cost of load vs. weights of CCGTs



We can further expand our analysis to the magnitude of new entry capacity. We take #1 as the baseline and then case #10, #19 and #28 can be viewed as sensitivities off baseline (#1). Between these four cases, they have exactly the same entry pattern in every year except in year 2009 and 2010. As shown in the figure below, these four cases have different weights of CCGTs in 2009 and 2010 ranging from 100%, 75%, 50% to 0%. Moving from #1 to #10, to #19 and to #28, the cost of load increases as the weight of CCGTs decreases.

Figure 7. Illustration of sensitivities of magnitudes of new entry capacity

Year in which entry scenarios differ

1) % of CCGTs in the new entry profile in each year

	2008	2009	2010	2011	2012	2013	2014	2015
#1	0%	100%	100%	100%	100%	100%	0%	100%
#10	0%	75%	75%	100%	100%	100%	0%	100%
#19	0%	50%	50%	100%	100%	100%	0%	100%
#28	0%	0%	0%	100%	100%	100%	0%	100%

2) CCGTs incremental new entry in MW (FOR-adjusted)

	2008	2009	2010	2011	2012	2013	2014	2015
#1	-	986	1,951	2,526	2,927	3,322	3,322	3,799
#10	-	740	1,463	2,038	2,439	2,835	2,835	3,311
#19	-	493	976	1,550	1,951	2,347	2,347	2,823
#28	-	-	-	575	976	1,371	1,371	1,848

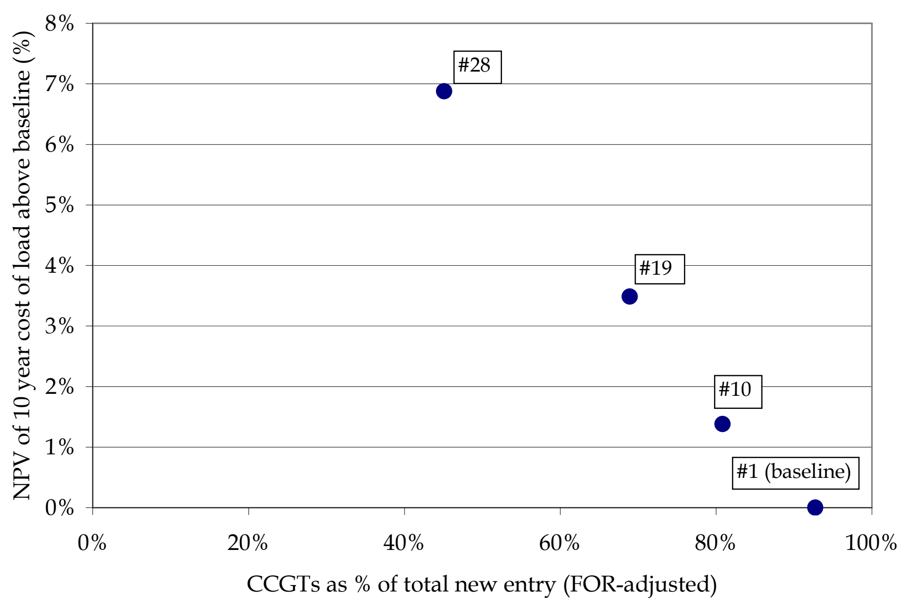
3) CCGTs as % of total new entry (FOR-adjusted)

#1	93%
#10	81%
#19	69%
#28	45%

4) NPV of 10 years cost of load above baseline (#1)

#1	0.0%
#10	1.4%
#19	3.5%
#28	6.9%

Figure 8. CCGTs as % of total new entry (FOR-adjusted) vs. NPV of 10 years cost of load above base line (#1)



4 Testing optimal profile against sensitivities

We selected our optimal entry profile based on our basecase, or "expected" system conditions over the next ten years. However, system planning is not simply an exercise in planning for the "expected" conditions, but rather involves also planning for reasonable contingencies which can be expected to arise. These contingencies may increase system needs, meaning our optimal profile in the basecase may provide insufficient resources; contingencies may also decrease system needs, in which case we will have expended scarce resources to meet needs which did not arise.

To test the durability of our optimal entry profile against alternative system conditions, we designed six sensitivity cases. These cases included:

- low nuclear availability: nuclear outages of 516 MW (Pickering B Unit 5, 6 and 7) scheduled for 2012, 2013 and 2014 for six months end up taking significantly longer than expected, with each plant being out of service for one year

- high nuclear availability: evolutions in maintenance procedures and technological advances allow the outages to be delayed to a point outside of the ten year forecast horizon

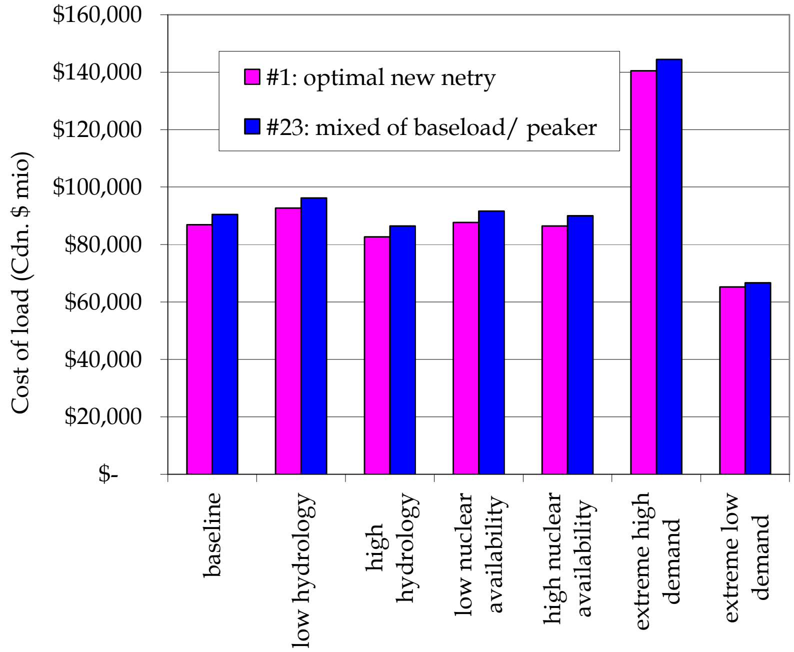
- low hydrology: Ontario experiences the five driest years on record back to back; that is, based on 27 years of data available to us, conditions over the next ten years are assumed to reflect the driest conditions experienced

- high hydrology: Ontario experiences the five wettest years on record back to back, derived in a fashion similar to the case described above

- extreme weather: According to IESO's *10-Year Outlook*, the forecast peak demand in 2015 is 26,874 MW under the normal weather condition, with a peak demand of 29,759 MW in 2015 under the extremely weather condition. This represents a difference of 11%. We thus escalate up and down the hourly demand by 11% to derive the extremely high and low demand scenario

In all of the six sensitivity cases, the optimal case selected under base case conditions also appeared to be the most economic under the alternative system conditions. The relative viability of peaking versus baseload plant depends on the shape of the load duration curve; based on the economic parameters we assumed for SCGTs and CCGTs, the load shape needs to be such that a peaking plant would run less than 30% of a time for a peaker to be preferred over a CCGT. Effectively, superpeak prices need to be substantially different from the mean for peaking plant to be the preferred entry choice. Interestingly, the economics of adding peaking capacity improve most not under the high demand/low supply cases, but rather in cases in which low demand occurs. The graphic below shows the results.

Figure 9. NPV cost of load for optimal entry case and alternative entry case under 6 scenarios



5 Exploring use of peaking capacity for insurance purposes

Peaking capacity can be thought of as having a value over and above its projected usage in a model of expected system conditions. Such capacity is also one of the cheapest forms of insurance against unforeseen events. This is true for several reasons: first, it has lower capital costs than other large system resources, and second, it can be built in smaller unit sizes.

For the purposes of our analysis, we have assumed that the smallest unit size for a peaking facility is 25 MW; although much smaller units are available, capital costs per unit begin to increase. Assuming current delivered Ontario gas prices of Cdn. $11.4 per MMBtu and an SCGT heat rate of 8,550 Btu/kWh, peaker operation results in an energy price of Cdn. $152.4 per MWh. A 25 MW peaker annual all-in cost if it earns zero margins from the energy market would be Cdn. $2,338,000. If we assume that value of lost load in Ontario is Cdn. $3,500 per MWh, a peaker is a rational insurance policy if one would otherwise expect at least 687 hours at value of lost load.

Figure 10. Number of hours at selected expected prices

expected price	# of hours	implied LF
$3,500	687	8%
$3,000	806	9%
$2,500	974	11%
$2,000	1,230	14%
$1,500	1,669	19%
$1,000	2,595	30%
$500	5,830	67%

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Over the past 12 months, Hourly Ontario Energy Price (HOEP) has exceeded Cdn. $500 one hour; while HOEP exceeded Cdn. $500 twelve hours since the market opened. In addition, IESO has issued power warning eight times/days since this summer, with 12 to 14 hours of power warning each time/day. This equates to approximately 100 hours of potential VoLL events.

Based on the scenarios we examined, the peaking units we propose to include in our optimal supply additions mix run a minimal amount of hours, between 0.1% and 3.2%. As such, it would appear that under most conditions, the amount of peaking capacity already provided for in the optimal supply mix would be sufficient to provide insurance against value of lost load events in most circumstances. However, we propose to perform additional statistical analysis in the next phase of this engagement[4] to verify whether it would be prudent to add additional amounts of peaking capacity based on their insurance value.

6 Implications

6.1 justification of need

Addition of peaking capacity in the amount that we recommend is justified for three reasons:

- over the near term, peaking capacity is the most practical means of obtaining the new capacity which is required by the year 2008;
- in the intermediate term, peaking capacity is the most economic way to meet small, but critical capacity shortfalls, such as the one projected for 2014; and
- despite the low expected load factor of the peaking capacity which is recommended for addition, this capacity is nonetheless a cost-effective form of insurance against value of lost load events.

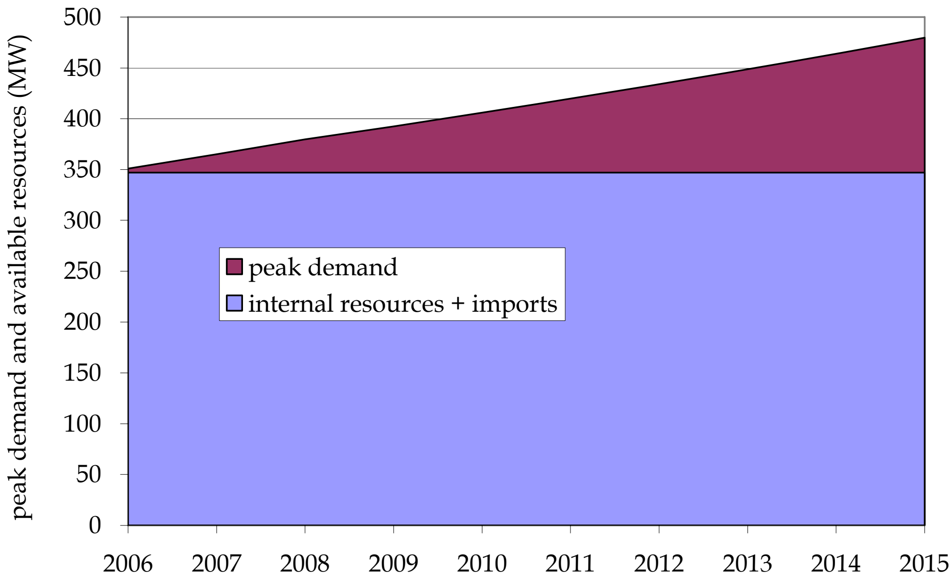
6.2 location in constrained regions

Given that we have identified a need for 339 MW of peaking capacity over the next ten years, it is rational to seek to place such capacity in the areas of the province where it can provide the greatest benefit, particularly areas which are experiencing transmission congestion such as the York region.

Current load in the York region is approximately 340 MW (2004), of which 317 MW can be obtained through transmission and up to 30 MW through local generation. IESO projects annual load growth in the York region of 3.4% per year over the next ten years. This suggests that York region may face a shortfall of 133 MW by 2015.

[4] Although we have expended substantial resources on this analysis, we can include such additional statistical analysis within the existing budget, and perform it before providing the final draft of this report.

Figure 11. Supply-demand balance in York region



Were it feasible to site new peaking capacity in the York region, and provided transmission for export from the region is sufficiently robust, it would appear that it is possible to meet both the short term needs of the York region and the longer term needs for peaking capacity in Ontario through a single solicitation for new capacity.

6.3 conditions which would increase peaking capacity need

Clearly, additional peaking capacity could be justified in Ontario were the load shape and price duration curve to adjust in such a fashion as to make prices in 30% or less of total hours significantly higher than average prices. Alternatively, a systematic decrease in water availability to hydro stations, some of which play a crucial peaking role, would also result in a greater need for peaking capacity. Locational needs for peaking capacity may be even greater as patterns of congestion on the transmission system change in response to plant shut downs and the location of new capacity.

6.4 associated beneficial policies

In addition to adding new peaking capacity, there are a number of other beneficial policies that can be pursued:

- **potential for demand response:** when considering peaking capacity solely as insurance, it is important to examine whether forms of demand response, if they were to be as reliable as a peaker, would be more economic;

- **future conversion of peaking units:** given that it is possible to build SCGTs in such a way that they can be converted to CCGT operation later, it may be useful to explore whether this is a configuration that the OPA would like to encourage in some way through its contracting processes;

- **timing of coal plant shutdown:** a study of the staging of the shut-down of the coal stations may determine that there is a way of placing such stations in an operational mode that would allow for the delay of capacity additions until sufficient capacity was required to justify construction of a baseload facility rather than a peaking facility;[5] and

- **required reserve margin assumptions:** it is worthwhile to test the assumption that a 15% internal reserve margin is required to maintain reliability as Ontario's generation mix changes and becomes more dispersed.

7 Next steps

We believe that three additional research initiatives will enhance our results prior to issuing the final paper:

testing assumptions: several assumptions are particularly important to determine the relative viability of peaking versus baseload additions. For example, we would like to in particular focus on the spread in capital costs between the two technologies, and to verify that the assumptions used are appropriate for Ontario. We would also like to test the impact of changing system dynamics, for example the number of starts and stops and minimum on and off times associated with each technology.

statistical approach to super-peak hours: our model produces results which are generally consistent with current forward markets, and with recent price duration curves in the Ontario market. However, we would like to refine and test our approach to consideration of superpeak hours, to assure that the magnitude and frequency of such events is being fully captured.

real options approach: we believe that one of the best approaches to considering the insurance value of peaking facilities relative to combined cycle units is to deploy an options valuation approach. We have extensive experience in using this methodology in Ontario, most recently in an examination of the Lennox facility. Such an approach essentially looks at power plants as a set of sequential call options, and values these options using standard financial techniques. Because this approach takes into account price volatility, plant flexibility, and expected price behavior, it allows for a more rigorous view of the value of the premium associated with paying for a peaking facility to stand and wait for extreme conditions.

Upon discussion with the OPA, we can begin pursuing some or all of the above enhancements to our analysis so as to provide further support for our results.

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[5] We recognize that such decisions are beyond the purview of the OPA.

8 Appendix A: Key assumptions for base case and sensitivities

Figure 12. Key assumptions for base case and sensitivities

	Baseline	Sensitivity # 1: low nuclear availability	Sensitivity # 2: high nuclear availability	Sensitivity # 3: low hydrology	Sensitivity # 4: high hydrology	Sensitivity # 5: extreme high demand	Sensitivity # 6: extreme low demand
Network topology	Ontario is modeled as a single zone region	same as Baseline	same as Baseline	same as Baseline	same as Baseline	same as Baseline	same as Baseline
Fuel (as of the first week of August 2005)	Gas price forecasts based on Henry Hub forwards, converted to Toronto City gate using historical basis differentials and with LDC charges added	same as Baseline	same as Baseline	same as Baseline	same as Baseline	same as Baseline	same as Baseline
Demand	Hourly load data based on 2004 hourly data, with load growth in line with IESO's published projected peak demand and energy	same as Baseline	same as Baseline	same as Baseline	same as Baseline	a 11% higher peak demand comparing to baseline	a 11% lower peak demand comparing to baseline
External markets	Current transfer capabilities dictated maximum capability (no intertie expansion is assumed based on modeled economics and status of proposed projects)	same as Baseline	same as Baseline	same as Baseline	same as Baseline	same as Baseline	same as Baseline
Capacity	All existing capacity included, as are those announced RFPs. Coal retirement schedules are in line with IESO's planned timeline. Pickering A Unit 1 is scheduled to return to service by 4Q 2005; no plan for proceeding with the refurbishment of Pickering A Units 2 and 3. Bruce A Unit 1 and Unit 2 are scheduled to return to service by spring 2009 and 2010, respectively. Bruce A Unit 3 is removed from service by the end of 2009. Pickering B Unit 5, 6, and 7 are put into 6-month maintenance outage in year 2011, 2012 and 2013, respectively.	a year-long nuclear outages of 516 MW (Pickering B Unit 5, 6 and 7) scheduled for 2011, 2012 and 2013	6-month nuclear maintenance outages for Pickering B Unit 5, 6, and 7 are delayed to a point outside of the ten year forecast horizon	Ontario experiences the five driest years on record back to back	Ontario experiences the five wettest years on record back to back	same as Baseline	same as Baseline

9 Appendix B: Cost estimates for new combined and simple cycle facilities

Note: *the estimates below assume that for either technology, plant developers enter into a contract with the OPA. Whereas we would normally differentiate between the returns required for a peaker and a CCGT, with the peaker having higher equity return requirements and a shorter payback period, in the case of a contracted asset with the same offtaker, we do not see the justification for such differentials. In both cases, the developer faces the same counterparty risk, the same fuel supply risks, and the reliability of the technology is not substantially different. As such, the main differences arise in capital costs and efficiencies between the two technologies.*

Figure 13. Summary of CCGT trigger price model for Ontario

New Entry Trigger Model - CCGT (Cdn.$ terms)

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
leverage	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%
debt interest rate	9%	9%	9%	9%	9%	9%	9%	9%	9%	9%
after-tax required equity return	16%	16%	16%	16%	16%	16%	16%	16%	16%	16%
corporate income tax rate	36%	36%	36%	36%	36%	36%	36%	36%	36%	36%
debt financing term	15	15	15	15	15	15	15	15	15	15
equity contribution capital recovery term	20	20	20	20	20	20	20	20	20	20
construction time (for capitalized expenses)	36	36	36	36	36	36	36	36	36	36
carrying charge until commissioning, $/kW	$ 125	$ 128	$ 130	$ 130	$ 133	$ 136	$ 138	$ 138	$ 141	$ 144
amortized capitalized expenses over debt term, $/kW/year	$ 13	$ 13	$ 13	$ 13	$ 13	$ 14	$ 14	$ 14	$ 14	$ 15
amortized carrying charge over debt term, $/MWh	**$1.8**	**$1.8**	**$1.9**	**$1.9**	**$1.9**	**$2.0**	**$2.0**	**$2.0**	**$2.0**	**$2.1**
average annual load factor	80%	80%	80%	80%	80%	80%	80%	80%	80%	80%
total capital cost, $/kW	$ 726	$ 740	$ 755	$ 755	$ 770	$ 785	$ 801	$ 801	$ 817	$ 833
debt-financed portion, $/kW	$ 435	$ 444	$ 453	$ 453	$ 462	$ 471	$ 481	$ 480	$ 490	$ 500
annual debt repayment, $/kW/year	$ 44	$ 45	$ 46	$ 46	$ 47	$ 48	$ 49	$ 49	$ 50	$ 51
annual debt repayment, $/MWh	**$ 6.3**	**$ 6.4**	**$ 6.6**	**$ 6.5**	**$ 6.7**	**$ 6.8**	**$ 6.9**	**$ 6.9**	**$ 7.1**	**$ 7.2**
equity-financed portion, $/kW	$ 290	$ 296	$ 302	$ 302	$ 308	$ 314	$ 320	$ 320	$ 327	$ 333
annual equity return, $/kW/year	$ 49	$ 50	$ 51	$ 51	$ 52	$ 53	$ 54	$ 54	$ 55	$ 56
annual equity return, $/MWh	**$ 7.0**	**$ 7.1**	**$ 7.3**	**$ 7.3**	**$ 7.4**	**$ 7.6**	**$ 7.7**	**$ 7.7**	**$ 7.9**	**$ 8.0**
fuel prices ($/MMBtu)	$ 11.4	$ 10.7	$ 10.2	$ 9.7	$ 9.4	$ 9.6	$ 9.7	$ 9.9	$ 10.1	$ 10.3
heat rate, Btu/kWh	6,333	6,333	6,333	6,143	6,143	6,143	6,143	5,959	5,959	5,959
fuel cost, $/MWh	**$ 71.9**	**$ 67.6**	**$ 64.3**	**$ 59.6**	**$ 57.7**	**$ 58.8**	**$ 59.8**	**$ 59.1**	**$ 60.1**	**$ 61.2**
variable O&M, $/MWh	$ 3.1	$ 3.2	$ 3.2	$ 3.3	$ 3.3	$ 3.4	$ 3.5	$ 3.5	$ 3.6	$ 3.7
fixed O&M, $/kW/year	$ 24.2	$ 24.5	$ 24.7	$ 24.9	$ 25.2	$ 25.4	$ 25.7	$ 26.0	$ 26.2	$ 26.5
fixed O&M, $/MWh	**$ 3.5**	**$ 3.5**	**$ 3.5**	**$ 3.6**	**$ 3.6**	**$ 3.6**	**$ 3.7**	**$ 3.7**	**$ 3.7**	**$ 3.8**
Break-even for new CCGT plant, $/MWh:	**$93.6**	**$89.6**	**$86.7**	**$82.2**	**$80.7**	**$82.1**	**$83.6**	**$83.0**	**$84.5**	**$86.0**
Fixed portion of NETP, $/kW:	**$130.0**	**$132.4**	**$134.8**	**$135.0**	**$137.4**	**$139.9**	**$142.5**	**$142.7**	**$145.3**	**$147.9**

Figure 14. Summary of SCGT trigger price model for Ontario

New Entry Trigger Model - SCGT (Cdn.$ terms)	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
leverage	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%
debt interest rate	9%	9%	9%	9%	9%	9%	9%	9%	9%	9%
after-tax required equity return	16%	16%	16%	16%	16%	16%	16%	16%	16%	16%
corporate income tax rate	36%	36%	36%	36%	36%	36%	36%	36%	36%	36%
debt financing term	15	15	15	15	15	15	15	15	15	15
equity contribution capital recovery term	20	20	20	20	20	20	20	20	20	20
construction time (for capitalized expenses)	24	24	24	24	24	24	24	24	24	24
carrying charge until commissioning, $/kW	$ 56	$ 57	$ 58	$ 58	$ 59	$ 61	$ 62	$ 62	$ 63	$ 64
amortized capitalized expenses over debt term, $/kW/year	$ 6	$ 6	$ 6	$ 6	$ 6	$ 6	$ 6	$ 6	$ 6	$ 7
amortized carrying charge over debt term, $/MWh	**$3.2**	**$3.3**	**$3.4**	**$3.4**	**$3.4**	**$3.5**	**$3.6**	**$3.6**	**$3.6**	**$3.7**
average annual load factor	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%
total capital cost, $/kW	$ 486	$ 496	$ 506	$ 506	$ 516	$ 526	$ 537	$ 537	$ 547	$ 558
debt-financed portion, $/kW	$ 292	$ 298	$ 304	$ 303	$ 310	$ 316	$ 322	$ 322	$ 328	$ 335
annual debt repayment, $/kW/year	$ 30	$ 30	$ 31	$ 31	$ 31	$ 32	$ 33	$ 33	$ 33	$ 34
annual debt repayment, $/MWh	**$ 16.9**	**$ 17.2**	**$ 17.6**	**$ 17.6**	**$ 17.9**	**$ 18.3**	**$ 18.6**	**$ 18.6**	**$ 19.0**	**$ 19.4**
equity-financed portion, $/kW	$ 195	$ 198	$ 202	$ 202	$ 206	$ 210	$ 215	$ 215	$ 219	$ 223
annual equity return, $/kW/year	$ 33	$ 33	$ 34	$ 34	$ 35	$ 36	$ 36	$ 36	$ 37	$ 38
annual equity return, $/MWh	**$ 18.7**	**$ 19.1**	**$ 19.5**	**$ 19.5**	**$ 19.9**	**$ 20.3**	**$ 20.7**	**$ 20.7**	**$ 21.1**	**$ 21.5**
fuel prices ($/MMBtu)	$ 11.4	$ 10.7	$ 10.2	$ 9.7	$ 9.4	$ 9.6	$ 9.7	$ 9.9	$ 10.1	$ 10.3
heat rate, Btu/kWh	8,550	8,550	8,550	8,294	8,294	8,294	8,294	8,045	8,045	8,045
fuel cost, $/MWh	**$ 97.1**	**$ 91.3**	**$ 86.8**	**$ 80.5**	**$ 77.9**	**$ 79.3**	**$ 80.8**	**$ 79.7**	**$ 81.2**	**$ 82.6**
variable O&M, $/MWh	$ 1.9	$ 1.9	$ 1.9	$ 2.0	$ 2.0	$ 2.0	$ 2.1	$ 2.1	$ 2.2	$ 2.2
fixed O&M, $/kW/year	$ 25.5	$ 25.7	$ 26.0	$ 26.2	$ 26.5	$ 26.8	$ 27.1	$ 27.4	$ 27.7	$ 28.0
fixed O&M, $/MWh	**$ 14.5**	**$ 14.7**	**$ 14.8**	**$ 15.0**	**$ 15.1**	**$ 15.3**	**$ 15.5**	**$ 15.6**	**$ 15.8**	**$ 16.0**
Break-even for new peaker plant, $/MWh:	**$152.4**	**$147.5**	**$144.0**	**$137.9**	**$136.3**	**$138.7**	**$141.2**	**$140.4**	**$142.9**	**$145.4**
Fixed portion of NETP, $/kW:	**$93.5**	**$95.1**	**$96.8**	**$97.0**	**$98.7**	**$100.5**	**$102.2**	**$102.5**	**$104.3**	**$106.1**

10 Appendix C: 36 alternative new entry portfolios

Figure 15. 36 alternative new entry portfolios (in percentage)

	2008	2009	2010	2011	2012	2013	2014	2015
total FOR-adjusted capacity needed (MW)	181	986	965	575	401	395	117	476
CCGT %	0%	100%/ 100% 75%/ 75% 50%/ 50% 0%/ 0%		100% 75% 0%	100%/ 100%/ 0%/ 100% 0%/ 0%/ 0%/ 0% 100%/ 100%/ 0%/0%			
1	0%	100%	100%	100%	100%	100%	0%	100%
2	0%	100%	100%	100%	100%	100%	0%	0%
3	0%	100%	100%	100%	0%	0%	0%	0%
4	0%	100%	100%	75%	100%	100%	0%	100%
5	0%	100%	100%	75%	100%	100%	0%	0%
6	0%	100%	100%	75%	0%	0%	0%	0%
7	0%	100%	100%	0%	100%	100%	0%	100%
8	0%	100%	100%	0%	100%	100%	0%	0%
9	0%	100%	100%	0%	0%	0%	0%	0%
10	0%	75%	75%	100%	100%	100%	0%	100%
11	0%	75%	75%	100%	100%	100%	0%	0%
12	0%	75%	75%	100%	0%	0%	0%	0%
13	0%	75%	75%	75%	100%	100%	0%	100%
14	0%	75%	75%	75%	100%	100%	0%	0%
15	0%	75%	75%	75%	0%	0%	0%	0%
16	0%	75%	75%	0%	100%	100%	0%	100%
17	0%	75%	75%	0%	100%	100%	0%	0%
18	0%	75%	75%	0%	0%	0%	0%	0%
19	0%	50%	50%	100%	100%	100%	0%	100%
20	0%	50%	50%	100%	100%	100%	0%	0%
21	0%	50%	50%	100%	0%	0%	0%	0%
22	0%	50%	50%	75%	100%	100%	0%	100%
23	0%	50%	50%	75%	100%	100%	0%	0%
24	0%	50%	50%	75%	0%	0%	0%	0%
25	0%	50%	50%	0%	100%	100%	0%	100%
26	0%	50%	50%	0%	100%	100%	0%	0%
27	0%	50%	50%	0%	0%	0%	0%	0%
28	0%	0%	0%	100%	100%	100%	0%	100%
29	0%	0%	0%	100%	100%	100%	0%	0%
30	0%	0%	0%	100%	0%	0%	0%	0%
31	0%	0%	0%	75%	100%	100%	0%	100%
32	0%	0%	0%	75%	100%	100%	0%	0%
33	0%	0%	0%	75%	0%	0%	0%	0%
34	0%	0%	0%	0%	100%	100%	0%	100%
35	0%	0%	0%	0%	100%	100%	0%	0%
36	0%	0%	0%	0%	0%	0%	0%	0%

Figure 16. NPV of 10 year cost of load for 36 alternative new entry portfolios

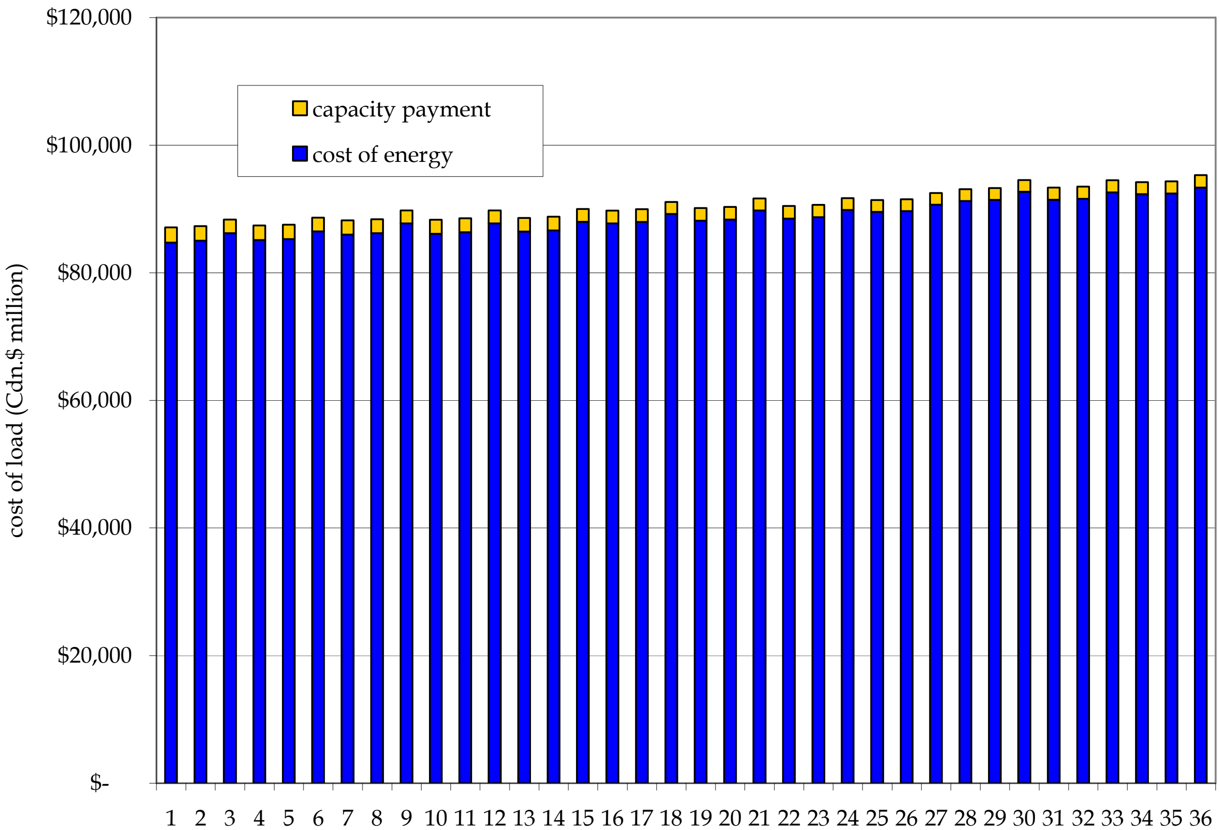

Figure 17. 36 alternative new entry portfolios (in MW (FOR-adjusted capacity))

	CCGT new entry in MW (FOR-adjusted capacity)									SCGT new entry in MW (FOR-adjusted capacity)							
	2008	2009	2010	2011	2012	2013	2014	2015		2008	2009	2010	2011	2012	2013	2014	2015
1	-	986	965	575	401	395	-	476	1	181	-	-	-	-	-	117	-
2	-	986	965	575	401	395	-	-	2	181	-	-	-	-	-	117	476
3	-	986	965	575	-	-	-	-	3	181	-	-	-	401	395	117	476
4	-	986	965	431	401	395	-	476	4	181	-	-	144	-	-	117	-
5	-	986	965	431	401	395	-	-	5	181	-	-	144	-	-	117	476
6	-	986	965	431	-	-	-	-	6	181	-	-	144	401	395	117	476
7	-	986	965	-	401	395	-	476	7	181	-	-	575	-	-	117	-
8	-	986	965	-	401	395	-	-	8	181	-	-	575	-	-	117	476
9	-	986	965	-	-	-	-	-	9	181	-	-	575	401	395	117	476
10	-	740	724	575	401	395	-	476	10	181	247	241	-	-	-	117	-
11	-	740	724	575	401	395	-	-	11	181	247	241	-	-	-	117	476
12	-	740	724	575	-	-	-	-	12	181	247	241	-	401	395	117	476
13	-	740	724	431	401	395	-	476	13	181	247	241	144	-	-	117	-
14	-	740	724	431	401	395	-	-	14	181	247	241	144	-	-	117	476
15	-	740	724	431	-	-	-	-	15	181	247	241	144	401	395	117	476
16	-	740	724	-	401	395	-	476	16	181	247	241	575	-	-	117	-
17	-	740	724	-	401	395	-	-	17	181	247	241	575	-	-	117	476
18	-	740	724	-	-	-	-	-	18	181	247	241	575	401	395	117	476
19	-	493	482	575	401	395	-	476	19	181	493	482	-	-	-	117	-
20	-	493	482	575	401	395	-	-	20	181	493	482	-	-	-	117	476
21	-	493	482	575	-	-	-	-	21	181	493	482	-	401	395	117	476
22	-	493	482	431	401	395	-	476	22	181	493	482	144	-	-	117	-
23	-	493	482	431	401	395	-	-	23	181	493	482	144	-	-	117	476
24	-	493	482	431	-	-	-	-	24	181	493	482	144	401	395	117	476
25	-	493	482	-	401	395	-	476	25	181	493	482	575	-	-	117	-
26	-	493	482	-	401	395	-	-	26	181	493	482	575	-	-	117	476
27	-	493	482	-	-	-	-	-	27	181	493	482	575	401	395	117	476
28	-	-	-	575	401	395	-	476	28	181	986	965	-	-	-	117	-
29	-	-	-	575	401	395	-	-	29	181	986	965	-	-	-	117	476
30	-	-	-	575	-	-	-	-	30	181	986	965	-	401	395	117	476
31	-	-	-	431	401	395	-	476	31	181	986	965	144	-	-	117	-
32	-	-	-	431	401	395	-	-	32	181	986	965	144	-	-	117	476
33	-	-	-	431	-	-	-	-	33	181	986	965	144	401	395	117	476
34	-	-	-	-	401	395	-	476	34	181	986	965	575	-	-	117	-
35	-	-	-	-	401	395	-	-	35	181	986	965	575	-	-	117	476
36	-	-	-	-	-	-	-	-	36	181	986	965	575	401	395	117	476

Figure 18. 36 alternative incremental new entry portfolios (in MW (FOR-adjusted capacity))

	CCGT incremental new entry in MW (FOR-adjusted)									SCGT incremental new entry in MW (FOR-adjusted)								
	2008	2009	2010	2011	2012	2013	2014	2015		2008	2009	2010	2011	2012	2013	2014	2015	CCGTs % as total new entry	SCGTs % as total new entry
1	-	986	1,951	2,526	2,927	3,322	3,322	3,799	1	181	181	181	181	181	181	298	298	93%	7%
2	-	986	1,951	2,526	2,927	3,322	3,322	3,322	2	181	181	181	181	181	181	298	775	81%	19%
3	-	986	1,951	2,526	2,526	2,526	2,526	2,526	3	181	181	181	181	582	978	1,095	1,571	62%	38%
4	-	986	1,951	2,382	2,783	3,179	3,179	3,655	4	181	181	181	325	325	325	442	442	89%	11%
5	-	986	1,951	2,382	2,783	3,179	3,179	3,179	5	181	181	181	325	325	325	442	918	78%	22%
6	-	986	1,951	2,382	2,382	2,382	2,382	2,382	6	181	181	181	325	726	1,121	1,238	1,715	58%	42%
7	-	986	1,951	1,951	2,352	2,748	2,748	3,224	7	181	181	181	756	756	756	873	873	79%	21%
8	-	986	1,951	1,951	2,352	2,748	2,748	2,748	8	181	181	181	756	756	756	873	1,349	67%	33%
9	-	986	1,951	1,951	1,951	1,951	1,951	1,951	9	181	181	181	756	1,157	1,552	1,669	2,146	48%	52%
10	-	740	1,463	2,038	2,439	2,835	2,835	3,311	10	181	427	669	669	669	669	786	786	81%	19%
11	-	740	1,463	2,038	2,439	2,835	2,835	2,835	11	181	427	669	669	669	669	786	1,262	69%	31%
12	-	740	1,463	2,038	2,038	2,038	2,038	2,038	12	181	427	669	669	1,070	1,465	1,583	2,059	50%	50%
13	-	740	1,463	1,894	2,296	2,691	2,691	3,167	13	181	427	669	812	812	812	930	930	77%	23%
14	-	740	1,463	1,894	2,296	2,691	2,691	2,691	14	181	427	669	812	812	812	930	1,406	66%	34%
15	-	740	1,463	1,894	1,894	1,894	1,894	1,894	15	181	427	669	812	1,214	1,609	1,726	2,203	46%	54%
16	-	740	1,463	1,463	1,865	2,260	2,260	2,736	16	181	427	669	1,243	1,243	1,243	1,361	1,361	67%	33%
17	-	740	1,463	1,463	1,865	2,260	2,260	2,260	17	181	427	669	1,243	1,243	1,243	1,361	1,837	55%	45%
18	-	740	1,463	1,463	1,463	1,463	1,463	1,463	18	181	427	669	1,243	1,645	2,040	2,157	2,634	36%	64%
19	-	493	976	1,550	1,951	2,347	2,347	2,823	19	181	674	1,156	1,156	1,156	1,156	1,274	1,274	69%	31%
20	-	493	976	1,550	1,951	2,347	2,347	2,347	20	181	674	1,156	1,156	1,156	1,156	1,274	1,750	57%	43%
21	-	493	976	1,550	1,550	1,550	1,550	1,550	21	181	674	1,156	1,156	1,558	1,953	2,070	2,547	38%	62%
22	-	493	976	1,406	1,808	2,203	2,203	2,680	22	181	674	1,156	1,300	1,300	1,300	1,417	1,417	65%	35%
23	-	493	976	1,406	1,808	2,203	2,203	2,203	23	181	674	1,156	1,300	1,300	1,300	1,417	1,894	54%	46%
24	-	493	976	1,406	1,406	1,406	1,406	1,406	24	181	674	1,156	1,300	1,701	2,097	2,214	2,691	34%	66%
25	-	493	976	976	1,377	1,772	1,772	2,249	25	181	674	1,156	1,731	1,731	1,731	1,848	1,848	55%	45%
26	-	493	976	976	1,377	1,772	1,772	1,772	26	181	674	1,156	1,731	1,731	1,731	1,848	2,325	43%	57%
27	-	493	976	976	976	976	976	976	27	181	674	1,156	1,731	2,132	2,528	2,645	3,121	24%	76%
28	-	-	-	575	976	1,371	1,371	1,848	28	181	1,167	2,132	2,132	2,132	2,132	2,249	2,249	45%	55%
29	-	-	-	575	976	1,371	1,371	1,371	29	181	1,167	2,132	2,132	2,132	2,132	2,249	2,726	33%	67%
30	-	-	-	575	575	575	575	575	30	181	1,167	2,132	2,132	2,533	2,929	3,046	3,522	14%	86%
31	-	-	-	431	832	1,228	1,228	1,704	31	181	1,167	2,132	2,276	2,276	2,276	2,393	2,393	42%	58%
32	-	-	-	431	832	1,228	1,228	1,228	32	181	1,167	2,132	2,276	2,276	2,276	2,393	2,869	30%	70%
33	-	-	-	431	431	431	431	431	33	181	1,167	2,132	2,276	2,677	3,072	3,190	3,666	11%	89%
34	-	-	-	-	401	797	797	1,273	34	181	1,167	2,132	2,707	2,707	2,707	2,824	2,824	31%	69%
35	-	-	-	-	401	797	797	797	35	181	1,167	2,132	2,707	2,707	2,707	2,824	3,300	19%	81%
36	-	-	-	-	-	-	-	-	36	181	1,167	2,132	2,707	3,108	3,503	3,621	4,097	0%	100%

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Figure 19. 36 alternative new entry portfolios (in MW)

CCGT new entry in MW (ICAP) FOR= 2%									SCGT new entry in MW (ICAP) FOR= 12%								
	2008	2009	2010	2011	2012	2013	2014	2015		2008	2009	2010	2011	2012	2013	2014	2015
1	-	1,006	985	586	410	403	-	486	1	206	-	-	-	-	-	133	-
2	-	1,006	985	586	410	403	-	-	2	206	-	-	-	-	-	133	541
3	-	1,006	985	586	-	-	-	-	3	206	-	-	-	456	449	133	541
4	-	1,006	985	440	410	403	-	486	4	206	-	-	163	-	-	133	-
5	-	1,006	985	440	410	403	-	-	5	206	-	-	163	-	-	133	541
6	-	1,006	985	440	-	-	-	-	6	206	-	-	163	456	449	133	541
7	-	1,006	985	-	410	403	-	486	7	206	-	-	653	-	-	133	-
8	-	1,006	985	-	410	403	-	-	8	206	-	-	653	-	-	133	541
9	-	1,006	985	-	-	-	-	-	9	206	-	-	653	456	449	133	541
10	-	755	738	586	410	403	-	486	10	206	280	274	-	-	-	133	-
11	-	755	738	586	410	403	-	-	11	206	280	274	-	-	-	133	541
12	-	755	738	586	-	-	-	-	12	206	280	274	-	456	449	133	541
13	-	755	738	440	410	403	-	486	13	206	280	274	163	-	-	133	-
14	-	755	738	440	410	403	-	-	14	206	280	274	163	-	-	133	541
15	-	755	738	440	-	-	-	-	15	206	280	274	163	456	449	133	541
16	-	755	738	-	410	403	-	486	16	206	280	274	653	-	-	133	-
17	-	755	738	-	410	403	-	-	17	206	280	274	653	-	-	133	541
18	-	755	738	-	-	-	-	-	18	206	280	274	653	456	449	133	541
19	-	503	492	586	410	403	-	486	19	206	560	548	-	-	-	133	-
20	-	503	492	586	410	403	-	-	20	206	560	548	-	-	-	133	541
21	-	503	492	586	-	-	-	-	21	206	560	548	-	456	449	133	541
22	-	503	492	440	410	403	-	486	22	206	560	548	163	-	-	133	-
23	-	503	492	440	410	403	-	-	23	206	560	548	163	-	-	133	541
24	-	503	492	440	-	-	-	-	24	206	560	548	163	456	449	133	541
25	-	503	492	-	410	403	-	486	25	206	560	548	653	-	-	133	-
26	-	503	492	-	410	403	-	-	26	206	560	548	653	-	-	133	541
27	-	503	492	-	-	-	-	-	27	206	560	548	653	456	449	133	541
28	-	-	-	586	410	403	-	486	28	206	1,121	1,096	-	-	-	133	-
29	-	-	-	586	410	403	-	-	29	206	1,121	1,096	-	-	-	133	541
30	-	-	-	586	-	-	-	-	30	206	1,121	1,096	-	456	449	133	541
31	-	-	-	440	410	403	-	486	31	206	1,121	1,096	163	-	-	133	-
32	-	-	-	440	410	403	-	-	32	206	1,121	1,096	163	-	-	133	541
33	-	-	-	440	-	-	-	-	33	206	1,121	1,096	163	456	449	133	541
34	-	-	-	-	410	403	-	486	34	206	1,121	1,096	653	-	-	133	-
35	-	-	-	-	410	403	-	-	35	206	1,121	1,096	653	-	-	133	541
36	-	-	-	-	-	-	-	-	36	206	1,121	1,096	653	456	449	133	541

Figure 20. 36 alternative incremental new entry portfolios (in MW)

CCGT incremental new entry in MW (ICAP)

	2008	2009	2010	2011	2012	2013	2014	2015
1	-	1,006	1,991	2,577	2,987	3,390	3,390	3,876
2	-	1,006	1,991	2,577	2,987	3,390	3,390	3,390
3	-	1,006	1,991	2,577	2,577	2,577	2,577	2,577
4	-	1,006	1,991	2,431	2,840	3,244	3,244	3,730
5	-	1,006	1,991	2,431	2,840	3,244	3,244	3,244
6	-	1,006	1,991	2,431	2,431	2,431	2,431	2,431
7	-	1,006	1,991	1,991	2,400	2,804	2,804	3,290
8	-	1,006	1,991	1,991	2,400	2,804	2,804	2,804
9	-	1,006	1,991	1,991	1,991	1,991	1,991	1,991
10	-	755	1,493	2,080	2,489	2,892	2,892	3,379
11	-	755	1,493	2,080	2,489	2,892	2,892	2,892
12	-	755	1,493	2,080	2,080	2,080	2,080	2,080
13	-	755	1,493	1,933	2,342	2,746	2,746	3,232
14	-	755	1,493	1,933	2,342	2,746	2,746	2,746
15	-	755	1,493	1,933	1,933	1,933	1,933	1,933
16	-	755	1,493	1,493	1,903	2,306	2,306	2,792
17	-	755	1,493	1,493	1,903	2,306	2,306	2,306
18	-	755	1,493	1,493	1,493	1,493	1,493	1,493
19	-	503	995	1,582	1,991	2,395	2,395	2,881
20	-	503	995	1,582	1,991	2,395	2,395	2,395
21	-	503	995	1,582	1,582	1,582	1,582	1,582
22	-	503	995	1,435	1,845	2,248	2,248	2,734
23	-	503	995	1,435	1,845	2,248	2,248	2,248
24	-	503	995	1,435	1,435	1,435	1,435	1,435
25	-	503	995	995	1,405	1,808	1,808	2,295
26	-	503	995	995	1,405	1,808	1,808	1,808
27	-	503	995	995	995	995	995	995
28	-	-	-	586	996	1,399	1,399	1,885
29	-	-	-	586	996	1,399	1,399	1,399
30	-	-	-	586	586	586	586	586
31	-	-	-	440	849	1,253	1,253	1,739
32	-	-	-	440	849	1,253	1,253	1,253
33	-	-	-	440	440	440	440	440
34	-	-	-	-	410	813	813	1,299
35	-	-	-	-	410	813	813	813
36	-	-	-	-	-	-	-	-

SCGT incremental new entry in MW (ICAP)

	2008	2009	2010	2011	2012	2013	2014	2015
1	206	206	206	206	206	206	339	339
2	206	206	206	206	206	206	339	880
3	206	206	206	206	662	1,111	1,244	1,786
4	206	206	206	369	369	369	502	502
5	206	206	206	369	369	369	502	1,044
6	206	206	206	369	825	1,274	1,407	1,949
7	206	206	206	859	859	859	992	992
8	206	206	206	859	859	859	992	1,533
9	206	206	206	859	1,315	1,764	1,897	2,439
10	206	486	760	760	760	760	893	893
11	206	486	760	760	760	760	893	1,435
12	206	486	760	760	1,216	1,665	1,798	2,340
13	206	486	760	923	923	923	1,056	1,056
14	206	486	760	923	923	923	1,056	1,598
15	206	486	760	923	1,379	1,828	1,962	2,503
16	206	486	760	1,413	1,413	1,413	1,546	1,546
17	206	486	760	1,413	1,413	1,413	1,546	2,088
18	206	486	760	1,413	1,869	2,318	2,451	2,993
19	206	766	1,314	1,314	1,314	1,314	1,447	1,447
20	206	766	1,314	1,314	1,314	1,314	1,447	1,989
21	206	766	1,314	1,314	1,770	2,219	2,353	2,894
22	206	766	1,314	1,477	1,477	1,477	1,611	1,611
23	206	766	1,314	1,477	1,477	1,477	1,611	2,152
24	206	766	1,314	1,477	1,933	2,383	2,516	3,057
25	206	766	1,314	1,967	1,967	1,967	2,100	2,100
26	206	766	1,314	1,967	1,967	1,967	2,100	2,642
27	206	766	1,314	1,967	2,423	2,872	3,006	3,547
28	206	1,326	2,423	2,423	2,423	2,423	2,556	2,556
29	206	1,326	2,423	2,423	2,423	2,423	2,556	3,097
30	206	1,326	2,423	2,423	2,879	3,328	3,461	4,003
31	206	1,326	2,423	2,586	2,586	2,586	2,719	2,719
32	206	1,326	2,423	2,586	2,586	2,586	2,719	3,261
33	206	1,326	2,423	2,586	3,042	3,491	3,625	4,166
34	206	1,326	2,423	3,076	3,076	3,076	3,209	3,209
35	206	1,326	2,423	3,076	3,076	3,076	3,209	3,750
36	206	1,326	2,423	3,076	3,532	3,981	4,114	4,656