A PROPOSED BASIS FOR ESTIMATING THE STANDARD SUPPLY SERVICE REFERENCE PRICE UPON OPENING OF THE RETAIL ELECTRICITY MARKET IN ONTARIO, CANADA

Prepared for:

The Ontario Energy Board

Prepared by:

PHB Hagler Bailly, Inc.
1776 Eye Street, NW
Suite 500
Washington, DC 20006
(202) 223-6665

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1 INTRODUCTION

Standard Supply Service (SSS) is the electricity supply service provided by distributors to customers that do not wish to choose a retail supply. The Ontario Energy Board (the Board) requested short-term specialized technical consulting services relating to the development of the reference price and the associated price band for Standard Supply Service. The Ontario Energy Board engaged PHB Hagler Bailly to provide the following:

- A brief and concise study of the current state of the Ontario electricity market.
- A proposed methodology for calculating the reference price for SSS customers served directly by distributors.
- A calculation of the initial reference price for the period following the opening of the market.

This report addresses each of the requested tasks and is organized into six sections. This section introduces the report. Section 2 describes the current state of demand and supply in Ontario. Section 3 summarizes key aspects of the Market Power Mitigation Agreement (MPMA). Section 4 discusses the potential for early decontrol. Section 5 describes a methodological approach for projecting market prices for electricity in Ontario during the first year of market opening and presents the results of this approach. Section 6 presents a calculation of the reference price in Ontario, based on the discussion in the prior sections.

2 DEMAND AND SUPPLY IN ONTARIO

2.1 Load in Ontario

Ontario load usually peaks in the winter, although the past two years have experienced summer peaking, due to warmer than normal winter and unusually hot summer weather resulting from La Niña and El Niño. The highest peak demand in the history of Ontario occurred in January 1994, when demand reached 24,007 MW. Peak demands in the summer and winter of 1999 were 23,435 MW and 23,308 MW, respectively. [1]

[1] Independent Electricity Market Operator, "18-Month Outlook: An Assessment of the Adequacy and Capability of the Ontario Electricity System," March 2000 to August 2001, IPOP_REP_0002, March 17, 2000, p. 2.

Annual electricity demand in Ontario in 1998 was 139.5 TWh, and is expected to grow over the next few years.[2] The following table illustrates projected demand and consumption through 2003.

Exhibit 2-1
Projected Demand for Electricity in Ontario

Resource	2000	2001	2002	2003
Total Energy Use (TWh)[3]	143.6	144.7	NA	NA
Median Demand, with Reserve (MW)[4]	27,158	27,516	27,877	28,359
Median Demand, without Reserve (MW)[5]	23,015	23,123	23,231	23,437

2.2 Generating Capacity in Ontario

Ontario has approximately 28,000 MW of generating capacity. Ontario Power Generation, Inc. (OPGI) is the largest generator in Ontario, supplying about 85 percent of electricity consumed in Ontario. OPGI owns approximately 80 generating stations, consisting of hydroelectric, nuclear, and fossil plants.[6] Electricity also is produced by non-utility generators (NUGs) under power purchase agreements.

2 Ibid.

3 Ibid. Forecasts not available for 2002 and 2003.

4 Ontario Power Generation, "Electricity Demand and Supply in Ontario: A Report on the State of Electricity Demand and Supply within Ontario in the Period 2000 to 2003," December 1999, p. 12.

5 Calculated by removing required reserve assumption. Ontario Power Generation, "Electricity Demand and Supply in Ontario: A Report on the State of Electricity Demand and Supply within Ontario in the Period 2000 to 2003," December 1999, p. 11.

6 Ontario Power Generation, www.ontariopowergeneration.com/newgen/default.asp

Generation assets in Ontario are summarized in the following table.

Exhibit 2-2
In-Service Generating Resources in Ontario[7]
Year 2000

Resource	Capacity (MW)	Percent
OPGI	25,734	91.2%
Contract Generators	1,690	6.0%
Dispatchable Demand	600	2.1%
Contract Purchases	200	0.7%
Ontario Total	**28,224**	**100%**

Ontario traditionally has planned to have a reserve requirement of 18 percent in the first year, increasing by 1 percentage point for each following year.[8] This level of reserve is consistent with the goals of the surrounding North American Electric Reliability Council (NERC) regions. Currently, Ontario's reserve margin is less than projected due to the lay-up of the Pickering units in 1998.

According to OPGI's report on Electricity Demand and Supply in Ontario, there may be some risk of having to rely on interruptible loads to meet median forecast demand during winter 2000.[9] Under the high forecast, support from interconnected supplies or other control actions may be necessary. A similar situation is projected for the following winter. In the winter of 2002, the expected return of two Pickering A units should provide adequate supply for the market to meet the median forecast. In addition, new supply by announced projects should relieve the apparently tight supply.[10]

The effect that Ontario's tight supply will have on market prices will depend, in part, on the supply and demand in neighboring jurisdictions. Capacity margins in ECAR (Michigan's NERC region) and NPCC (New York's NERC region) indicate tight markets, especially in ECAR.

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7 Independent Electricity Market Operator, "18-Month Outlook: An Assessment of the Adequacy and Capability of the Ontario Electricity System," March 2000 to August 2001, IPOP_REP_0002, March 17, 2000, p. 4.

8 Ontario Power Generation, "Electricity Demand and Supply in Ontario: A Report on the State of Electricity Demand and Supply within Ontario in the Period 2000 to 2003," December 1999, p. 11.

9 Ibid.

10 Ontario Power Generation, "Electricity Demand and Supply in Ontario: A Report on the State of Electricity Demand and Supply within Ontario in the Period 2000 to 2003," December 1999, p. 12.

Capacity margins for Ontario's neighboring NERC regions for 1998 and 2007 are presented in the following tables.

Exhibit 2-3
Reserve Margins for NERC Regions Surrounding Ontario[11]

1998 Capacity Margins

NERC Region	Internal Demand (MW)	Net Capacity Resources (MW)	Capacity Margin (% of Capacity)
ECAR	94,725	105,106	13.3%
MAAC	48,846	56,155	17.1%
MAIN	47,522	52,160	13.4%
MAPP-US	30,407	34,027	17.1%
NPCC-US	50,240	60,729	17.3%
US Total	**648,694**	**737,855**	**16.2%**

Exhibit 2-4
Reserve Margins for NERC Regions Surrounding Ontario[12]

2007 Projected Capacity Margins

NERC Region	Internal Demand (MW)	Net Capacity Resources (MW)	Capacity Margin (% of Capacity)
ECAR	109,951	120,314	11.8%
MAAC	55,387	56,465	5.1%
MAIN	54,690	61,279	15.0%
MAPP-US	34,072	33,896	7.6%
NPCC-US	56,875	59,851	5.0%
US Total	**760,267**	**809,824**	**10.3%**

11 *NERC*, 1998 Reliability Assessment: 1998 – 2007, Table 1, p. 11.

12 Ibid.

2.3 Development of New Generation

In addition to the return of Pickering A to service in 2001 through 2003, over 3,000 MW of new generation has been announced. Industry trade journals have listed new units that have been announced or are under development. These are summarized in the following table.

Exhibit 2-5
Announced Development of New Generation
In Ontario[13]

Developer	Location of Plant	Capacity (MW)	Proposed Date of Operation	UnitType / Fuel
Sithe	Brampton	800	2002	Combined cycle gas turbine
Sithe	Mississauga	800	2002	Combined cycle gas turbine
TransAlta	Sarnia	535	Late 2001/ early 2002	Cogeneration (natural gas)
CU Power[14]	Lakeview station (Toronto)	550	2003	Combined cycle gas turbine
Toronto Hydro/ Boralex	Toronto Portlands	250	Late 2001	Cogeneration (natural gas)
Sentinel Power	Sarnia	100	Late 2000	Cogeneration (natural gas)

Reportedly, the development of several of these projects has come to a standstill. Reasons that have been cited for the pause in development include uncertainties in the newly competitive provincial wholesale and retail electricity markets, including the ongoing market power of OPGI, a cap on the spot market price of power, and what developers see as onerous transmission charges.[15] The Sithe projects, however, continue to be developed for the Greater Toronto Area. A representative from Sithe has stated "We're pretty much on schedule to start construction early in

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13 Ontario Power Generation, "Electricity Demand and Supply in Ontario: A Report on the State of Electricity Demand and Supply within Ontario in the Period 2000 to 2003," December 1999, p. 9.

14 Ontario Hydro, Toronto Hydro, Hydro Missasauga and CU Power of Calgary originally were developing the plant, to be called Lakeview New Generation. Hydro Missassauga has since dropped out of the project, citing Board decisions related to Standard Supply Service procurement as the reason.

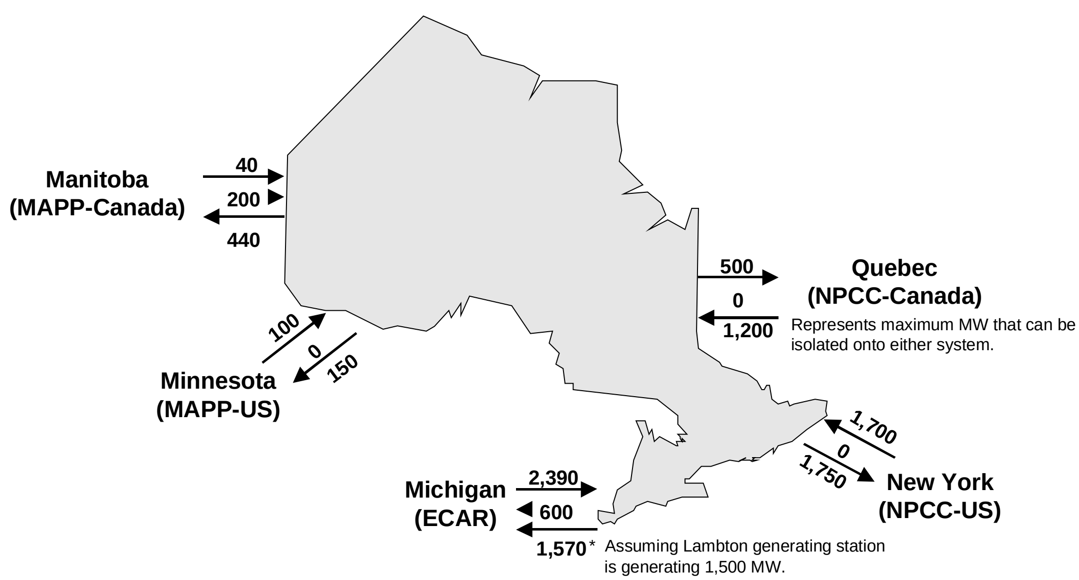
15 "Independent Projects Stall in Ontario's New Market," *Electricity Daily*, Volume 14, Number 92, Friday, May 12, 2000.

2001, for completion in 2003."[16] Presumably, investors in the plants that are moving forward expect to receive sufficient revenues to cover their costs and obtain an adequate return on their investment in the Ontario market.

2.4 Transmission Interties Within Ontario and With Other Regions

Competing with generation in Ontario will be generation from neighboring jurisdictions. Ontario's electricity grid is interconnected with the power grids of Manitoba, Quebec and the states of New York, Michigan, and Minnesota. Hydro One Services Network (Hydro One), the owner of the Ontario transmission system, owns 17 interconnection facilities with neighboring provinces and U.S. states. Normal energy flows during summer months at these interconnections are represented in the following graph.

Exhibit 2-6
NERC 1999 Summer Assessment
Normal Base Electricity Transfer and Incremental Transfer
(MW)[17]



It is clear from the graph above that Manitoba and Minnesota have little interconnection capability. Intertie capability with Michigan and New York is much larger. In addition, the

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16 Ibid., quoting Al Barnstaple, Sithe's director of development for Canada.

17 *NERC*, 1999 Summer Assessment: Reliability of Bulk Electricity Supply in North America, June 1999, p. 17.

connections with Michigan and New York result in loop flows by which power may flow through Ontario from Michigan to New York instead of through US transmission systems.

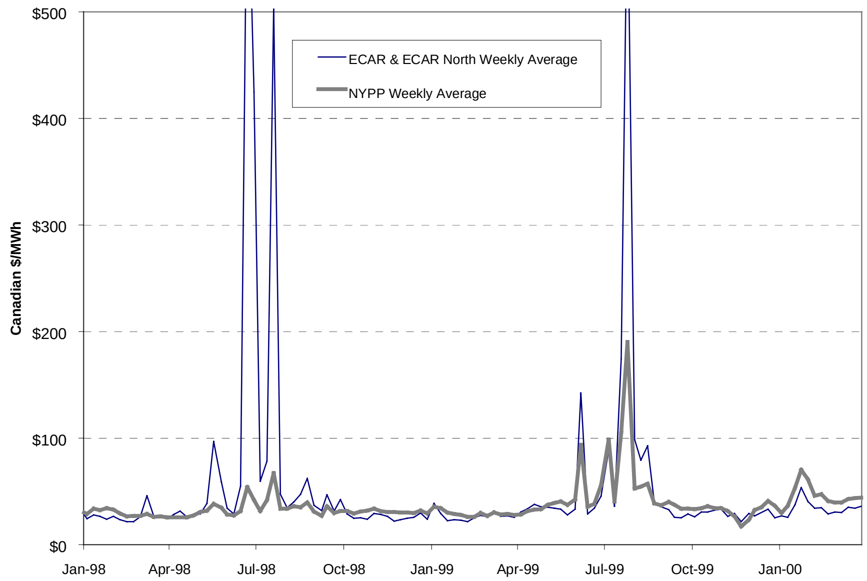
Quebec is distinct from other markets connected to Ontario, because Quebec's grid is not synchronized to Ontario's grid. As a result, the interconnection capability simply measures the hydroelectric generating units located in each province that are connected to both grids and can be synchronized to either one. Other generating units in Quebec would not have the capability to export into Ontario.

There has been discussion related to expanding existing transmission interties to other jurisdictions. To the extent existing interconnection capability is expanded, Ontario market participants may have increased ability to import from or export to other electricity markets. However, these expansions are not scheduled to be implemented during the first year after market opening.

After the Ontario wholesale electricity market opens, it is likely that there will be significant electricity exchange between Ontario and the U.S. In particular, one would expect that Ontario prices will equilibrate with prices in Michigan (the ECAR NERC region) and New York (the NPCC NERC region) so long as there is available capacity on the interconnection. However, as the interconnection capacity becomes filled, price differentials between jurisdictions may persist.

Due to the interconnection capability, historic prices in interconnected jurisdictions may provide an indication of what prices might have been in Ontario during the same time period. The following charts show estimated average weekly prices based on *Power Market Week* surveys for ECAR and NPCC West for the period January 1998 through March 2000.

Exhibit 2-7
ECAR/ECAR North and NPCC West
Historical Weekly Average Peak Energy Prices
($/MWh in Nominal Dollars)[18]



Volatility in the charts above mask the historic averages in the U.S. markets that are interconnected with Ontario. The following table indicates the annual average prices for these electricity markets. The higher average prices in ECAR during 1998 and 1999 reflect the summer price spikes that have occurred due to high demand. NPCC, a region that has competitive markets and is separated from ECAR by Ontario and the Pennsylvania-Jersey-Maryland Interconnection, did not experience such extreme price spikes.

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18 *Power Market Week* price index database. Dollars have been converted to Canadian dollars assuming a US Dollar: Canadian Exchange Rate of 1:1.50.

Exhibit 2-8
Historical Annual Average Energy Prices
($/MWh in Nominal Dollars)[19]

Year	Average Electricity Price	
	ECAR & ECAR North	**NPCC (west)**
1998	$63.99	$32.53
1999	$51.56	$41.70
2000 (through 3/31)	$34.68	$45.97

Another indication of the impact market prices in other jurisdictions may have in Ontario is the historic level of imports and exports of power scheduled by OPGI and the average cost of these power flows. As discussed above, Ontario has large interconnections with New York and Michigan. As a result, power exported to these two jurisdictions accounted for 75 percent of total exports in 1998 and 1999. Power imported from these jurisdictions accounted for almost 75 percent of total imports in 1998 and 50 percent of total imports in 1999.[20] The following table provides more detail on the source and average price of Ontario electricity imports and exports.

19 *Power Market Week* price index database. Dollars have been converted to Canadian dollars assuming a US Dollar: Canadian Exchange Rate of 1:1.50. The average is a straight average of the weighted on-peak and off-peak average daily price, and does not reflect volumes traded at each price.

20 Ontario imported an abnormally large volume of electricity from Manitoba in 1999.

Exhibit 2-9
Historical Ontario Electricity Exports and Imports[21]

Interconnected Jurisdiction	1998		1999	
	Exports	Imports	Exports	Imports
Amount of Power (MWh)				
Manitoba	35,827	473,720	27,738	1,462,895
Michigan	2,025,492	3,556,768	2,136,630	2,513,173
Minnesota	57,119	67,322	236,347	11,067
New York	405,680	1,402,304	1,338,181	754,794
Quebec	699,528	1,166,478	877,804	1,680,245
Total MWh	3,223,646	6,666,592	4,616,700	6,422,174
Revenues ($)	98,767,865	123,036,824	200,973,826	182,950,248
Average Price ($/MWh)	30.64	18.46	43.53	28.49

There are two items to note from the data presented in this table. First, OPGI historically has exported power at a higher average price than the average price of power imported into Ontario.[22] Second, average prices of imports and exports increased between 1998 and 1999, but were still far below the fully allocated cost of a new entrant (see section 5).

3 MARKET POWER MITIGATION AGREEMENT

Given OPGI's ownership and control of such a substantial portion of generation, a Market Power Mitigation Agreement (MPMA) was negotiated through the combined efforts of the Ontario Government's Market Design Committee, the Ministry of Energy, Science and Technology, the Ministry of Finance, and the former Ontario Hydro. This agreement attempts to mitigate OPGI's ability to benefit from the exercise of market power and manipulation of prices. However, it does not prevent OPGI from exercising market power.

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[21] Docket number RP-1999-0044: Ontario Hydro Network Company Transmission Cost Allocation and Rate Design Proceeding. Ontario Power Generation Responses to Questions from Pollution Probe, Answer to Question 9, Reference: Boland evidence, page 5, question 13, February 3, 2000.

[22] The lower average price could reflect a variety of factors, including differences in timing of purchases versus sales, the low marginal cost of power produced by the hydroelectric units that are shared by Ontario and Quebec, and the lack of a transparent market for electricity in ECAR and Ontario.

The MPMA is not a single agreement between parties, but rather a series of legal vehicles that collectively implement the various aspects of the agreement. It has seven components:[23]

1. Licence Conditions on OPGI
2. Licence Conditions on the IMO
3. Licence Conditions on Ontario Hydro Service Company (OHSC) (i.e., Hydro One)
4. Licence Conditions on other Generators, Wholesale Sellers, and Retailers
5. Settlement Agreement between the IMO and OPGI
6. Minister's Directive and Referral to the OEB
7. Market Rule addressing Local Market Power.

The first and largest component of the agreement consists of licence conditions on OPGI. For the first four years after open access begins in Ontario, there is a revenue cap on the commodity supplied by OPGI of $38/MWh.[24] OPGI's revenues from sales at an average price (AP) above this level would be rebated to Ontario consumers. Under the agreement, OPGI has the explicit right to engage in unilateral actions to attempt to maintain hourly prices at levels that will result in the AP equaling the revenue cap. For any settlement period where the AP is greater than $38/MWh, the rebate would equal the difference between the AP and $38/MWh multiplied by the Contract Required Quantity (CRQ).

Licence conditions on distributors, wholesale sellers, and retailers require that the rebates received from the IMO be passed-through to end use customers. The MPMA consists of details for the calculation and payment of the rebate. A key aspect of the rebate calculation is the CRQ. The MPMA sets a pre-defined amount of power for which OPGI may receive a weighted average price of no more than $38/MWh. OPGI is required to reimburse the following amount:

(Average hourly market price weighted by the hourly CRQ amounts - $38/MWh) x CRQ

The manner in which this amount is reimbursed to customers has yet to be determined. Depending on the mechanics of the reimbursement, a customer may receive more or less than the CRQ percentage of total market production. However, on a provincial-wide basis, the cost of the CRQ can be assumed to be $38/MWh.

For amounts outside of the CRQ, OPGI will receive and customers will pay the market price for electricity. The weighted average price of the non-CRQ power will depend on how the actual dispatch compares to the CRQ hourly dispatch, and may be calculated by weighting the hourly market price by the total production of OPGI's units minus the CRQ for that hour. As already discussed, this measure is not an accurate representation of what customers will pay.

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23 Market Power Mitigation Detailed Description, www.ontariopowergeneration.com/newgen/mdc.asp

24 Ibid.

However, for purposes of setting a floor to this value, one can assume that OPGI will try to receive a market price for this power (either through contracts or the spot market) that is at least $38/MWh.

The proportion of total electricity consumed in Ontario that is subject to the $38/MWh price cap depends on total demand. The amount of the CRQ has been estimated by OPGI to be between 102 and 106 TWh.[25] This amount is not affected by the amount of exports sold by OPGI. Total load for the year 2001 is projected to be 144.7 TWh.[26] Thus, the amount of electricity subject to the MPMA can be assumed to be approximately 70 to 73 percent of total load. The remainder would be purchased at market prices.

4 POTENTIAL FOR EARLY DECONTROL

The MPMA rebate can be reduced by various adjustments. For example, the revenue cap and rebate mechanism could be altered if the IMO decides to implement a capacity market or initiate locational marginal pricing. The cap is scheduled to expire four years after market opening, but could be terminated earlier if the OEB determines that the 10-year decontrol target has been met.

The MPMA includes decontrol targets. By 42 months after open access, OPGI is required to relinquish control of at least 4,000 megawatts of Tier 2 capacity or enough of its generating output so that its share of the Tier 2 market is not greater than 35 percent.[27] Tier 2 capacity is the transfer capability of the interties, demand-side bidding, and all generation other than hydroelectric and nuclear. Within 10 years after market opening, OPGI is required to reduce its capacity in Ontario to 35 percent of total Ontario generating supply.

The MPMA also restricts OPGI's ability to import power. OPGI is restricted from importing more than 7.24 TWh during the winter months and 6.58 TWh during the summer months.[28] These import limits are increased upon the in-service date of new or upgraded intertie facilities. There are no restrictions on OPGI's ability to export power.

OPGI has announced plans for early decontrol. However, some of the early efforts have been stalled due to uncertainty in the market and the fear that these uncertainties would result in a large discounted value. For example, in December 1998, OPGI issued a request for expression of interest pertaining to the sale or renegotiation of its NUG contracts. A request for proposals was

25 Presentation by OPGI to the Board, March 31, 2000.

26 Independent Electricity Market Operator, "18-Month Outlook: An Assessment of the Adequacy and Capability of the Ontario Electricity System," March 2000 to August 2001, IPOP_REP_0002, March 17, 2000, p. 2.

27 Market Power Mitigation Detailed Description, www.ontariopowergeneration.com/newgen/mdc.asp

28 Ibid.

issued in 1999. The process was put on hold based on a recommendation from the NUG task force.

In February 2000, Ron Osborne, President and CEO of OPGI announced that the company is moving early to "decontrol" 4,000 megawatts (MW) of its generating capacity to encourage competition in the Ontario electricity marketplace.[29] In particular, OPGI is targeting roughly 4,000 MW of hydroelectric and fossil generation, including the 2,140 MW Lennox station near Kingston, and 1,140 MW Lakeview station in Mississauga. However, the Minister of the Environment has placed a moratorium on the sale of coal plants pending the enacting of rules for environmental protection, possibly including gas conversion.[30] In addition, OPGI has announced plans to sell or take on a private-sector partner for the Bruce nuclear units. The stated goal is to meet the first phase decontrol objective prior to the market's scheduled opening in November.

It is unclear how decontrol of the Lennox and Lakeview stations would affect the MPMA rebate mechanism. Both plants are peaking units; Lennox generates approximately 379 GWh per year and Lakeview generates approximately 1,608 GWh per year.[31] The combined production is only 2 TWh, less than 2 percent of the amount of generation subject to the MPMA rebate mechanism. Thus, even if OPGI decontrols Lakeview and Lennox, and the CRQ can be recalculated to consider this decontrol, the expected effect is not significant. Decontrol of the Bruce units may affect the MPMA rebate as these units provide baseload capacity. An even more significant change would occur if the cap was removed completely. However, even then, other market forces would serve to contain average electricity prices in Ontario.

Although OPGI has announced decontrol of these plants before market opening, uncertainty associated with the new market and potential environmental regulations is likely to delay proposed decontrol efforts. Lennox is composed of four units fueled by oil and natural gas. Two units currently are being converted to be able to burn natural gas in addition to oil. The other two were converted in 1998. Lakeview is fueled by low sulphur coal. The value of these plants will be significantly impacted by potential greenhouse-gas regulations currently being discussed in Canada. As already noted, coal plants can not be sold until the moratorium declared by the Minister of the Environment is lifted. A partnership on or a sale of the Bruce units may require lengthy negotiations, as a result of the provincial ownership and hazardous waste issues. As a result, the sale of these units could be postponed pending regulations that would provide some certainty for potential buyers.

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29 "Ontario Power Generation Announces Faster Decontrol," February 14, 2000, OPGI website: http://www.ontariopowergeneration.com/media/Feb142000spch.asp

30 "Ontario announces environmental moratorium on sale of all coal-fired electricity generation facilities," May 17, 2000, OPGI website: http://www.ene.gov.on.ca/envision/news/029.htm

31 "Facts on Lakeview and Lennox Generating Stations," February 14, 2000, OPGI website: http://www.ontariopowergeneration.com/media/News/Newsfeb142000backgrd.asp

5 METHODOLOGY AND RESULTS

As discussed above, OPGI retains control over a significant portion of total generating capacity in Ontario and is not prohibited from exercising market power. Given the rebate mechanism in the MPMA, there would be no reason for OPGI to let average prices fall below $38/MWh. Thus, $38/MWh serves as a floor for what market prices are likely to be. Furthermore, across the province, approximately 70 percent of electricity consumption ultimately can be expected to cost $38/MWh once the rebate mechanism is exercised.[32]

Theoretically, OPGI has the ability to raise electricity prices to an unlimited level. However, this ability would have to be exercised carefully. Neighboring jurisdictions are likely to respond to high price signals and fill the intertie capacity with imported power to receive the high prices. This will serve as a mitigating force and should equilibrate prices between markets unless the interties are filled. Also, OPGI is unlikely to want to send price signals that would encourage new entry sooner than is required. As a result, OPGI is likely to exercise its market power to allow market prices in Ontario to rise with market prices in neighboring jurisdictions above $38/MWh, but maintain an average market price in Ontario below the fully allocated cost of a new generator.

The fully allocated cost of a new entrant reflects the average annual electricity price that a new generating unit (assumed to be a combined cycle gas turbine) would require in order to be built. If there is a surplus of supply in Ontario, and market prices are sending the right signal, the average market price should be less than the fully allocated cost of a new combined cycle. If there is a shortage and new generation is required, average electricity prices should exceed the fully allocated cost of a new combined cycle to encourage new generation. Similar logic applies to prices in the markets that are interconnected with Ontario.

As discussed in section 2, the short-term supply of generating capacity in Ontario is projected to be tight. This normally would encourage price signals that exceed the fully allocated cost of a new entrant and encourage construction of new units. However, capacity is expected to come on line in 2002 and 2003, most likely offsetting these price signals. Furthermore, while OPGI has market power, there is likely to be little incentive for OPGI to entice new entrants by setting the average market price higher than the fully-allocated cost of a new combined cycle; thus, market prices are likely to be at or below this level.

The fully allocated cost of a new combined cycle can be assessed using a proforma spreadsheet model that incorporates assumptions regarding dispatch of a new entrant, heat rates, gas price projections, O&M costs, capital costs, debt structure, cost of equity and other revenue and cost items. The price for electricity could be set using an iterative process to determine the electricity price at which the net present value of equity cash flows equals zero (discounted at the required return to equity). This electricity price would yield a measure of the fully allocated cost of a new combined cycle.

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32 As discussed above, the actual cost of power for individual customers will depend on the rebate mechanism and the manner in which the rebate is distributed to individual consumers.

5.1 Fully Allocated Cost of a New Combined Cycle Plant

PHB Hagler Bailly calculated the fully allocated cost of a new entrant into the Ontario market. In a competitive environment, the price of electricity is set by the bid of the last generating unit dispatched. For a developer to commit to a new generating plant, the developer must believe that the prices the plant will receive for electricity it generates will, over time, be at least equal to the fully allocated costs of the plant. Fully allocated costs include both direct cash costs for fuel and O&M and recovery of and return on capital. The return on capital includes a required return on equity; rational power plant investors would have to expect to earn a minimum rate of return on the equity investment before undertaking the project. The announced plans for new generation indicate that many investors do believe that market prices in Ontario will be high enough to support the cost of a new combined cycle plant.

For the foreseeable future, combined cycle gas turbine units (CCGTs) are the most cost-effective source of new generating capacity for base and cycling loads in Ontario.[33] Indeed, only plans for gas-fired turbine units have been announced. While these units have higher delivered fuel costs than coal units, their initial capital costs are substantially lower than the capital required for a coal-fired unit. Furthermore, the lower heat rate of CCGTs offsets the higher fuel costs; new CCGTs have heat rates in the range of 6,600 to 6,900 Btu per kWh compared with new coal-fired heat rates in the range of 9,000 Btu per kWh. Environmental regulations that require scrubbers on new coal plants also make gas plants more attractive. Therefore, we used the fully allocated cost of a new CCGT to approximate the all-in expected price of electricity that would be received by a new entrant.

A projection of the first year electricity price required by a new CCGT is based on a cash flow model of a new CCGT assumed to be put into operation for the year 2001. The assumed characteristics of new CCGTs are presented below. These assumptions are based on PHB Hagler Bailly's extensive work in evaluating new generating projects and projecting future electricity prices. These characteristics described below capture typical financial, cost and operating parameters for new CCGT units.

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[33] Gas turbines may continue to be a cost-effective source of peaking capacity. These units combine a very low capital cost with a high variable operating cost. They are well suited for quick starts and operations over the limited number of hours needed to meet daily peak demands.

Exhibit 5-1
Input Assumptions to Cash Flow Analysis of New CCGTs[34]

Parameter	Assumption
Capacity of plant	375 MW
Physical/economic life of plant	30 years
Initial capacity factor	80%
Annual decline of capacity factor	0.5%
Capital cost of CCGT plant built in 2000 (per kW of installed capacity)	$724.25/kW ($2000)
Heat rate of CCGT plant built in 2000	6,600 Btu/kWh
Long-term debt portion of initial capital structure	51%
Life of debt	20 years
Long-term debt rate (nominal)	8.23%
Required rate of return on equity	13.63%
Effective income tax rate (combined federal and provincial)[35]	36.62% in 2001, declining to 30.12% in 2006, and constant thereafter
Annual property taxes as percent of initial capital[36]	1%
Annual insurance as percent of initial capital	0.5%
Capital cost allowance[37]	30% Declining Balance Basis
Annual fixed O&M plus A&G costs (per kW of installed capacity)	$22.89/kW-year ($2000)
Variable O&M costs	$2.19/MWh ($2000)
Average annual inflation rate	2.5%

PHB Hagler Bailly performed a cash flow analysis for a new plant coming on line on January 1, 2001. The analysis calculates the projection of electricity prices that the plant would need to cover its costs, including the required rate of return on equity. In and of itself, there is no unique pricing schedule that meets a return on equity target; prices could start low and rapidly

34 All costs are in Canadian dollars, converted from US dollars at an exchange rate of $1US:$1.50CAN

35 Based on discussion with Board staff.

36 Based on discussion with Board staff.

37 Based on discussion with Board staff.

increase or start high and decline or remain constant and still meet the target rate return on equity. However, another rule can be imposed that, in combination with the required return on equity, does yield a unique price series. This price series would be used to establish the minimum prices that a developer would expect before committing to build a new CCGT plant.

PHB Hagler Bailly used two methodologies to calculate a unique price series. One approach adjusts a single debt-service coverage ratio to provide the new plant with the required return on equity. The second approach assumes electricity price escalation would be at inflation and calculates the starting electricity price that would be required to obtain the required return on equity over the life of the project. Each of these is discussed in more detail below.

Methodology 1: Debt Service Coverage Ratio

For each new unit to be built, PHB Hagler Bailly estimated the minimum price series that met both a required after-tax target return on equity and an acceptable debt coverage ratio (i.e., EBITDA divided by debt service cost remained constant over life of debt financing). The calculated debt service coverage ratio was compared to a benchmark ratio of 2.0.[38] Accelerated capital cost allowance was assumed for tax purposes and long-term debt payments were calculated based on a fixed mortgage principle payment schedule paid annually. The cash flow analysis for each unit yields a set of annual electricity prices that must be met or exceeded for the plant to earn its required hurdle rate while maintaining an adequate debt service coverage ratio.

Methodology 2: Real Levelized Electricity Price

The real levelized electricity price approach sets electricity prices so that they increase at the same rate as inflation. Depending on the trajectory of assumed gas prices, early electricity prices may not provide a plant with sufficient cash flow to meet its desired debt coverage requirements, but higher prices in the later years of operation would make up for the low cash flows in the early years so that the plant still earns its targeted return on equity. Thus, unlike the Debt Service Coverage Ratio approach, coverage ratios required by financing institutions may not be met in the early years, especially if gas prices are projected to decline in real terms.

5.2 Gas Price Projection

A key component of the costs of a new combined cycle is the cost of fuel. To develop a fuel forecast, PHB Hagler Bailly used the short-term projection provided to the Board by Union Gas in March 2000 as part of the Union Gas rate hearings. PHB Hagler Bailly used this forecast to establish a base gas price for the year 2001. The base price (in real dollars) was escalated in accordance with the escalation of a long-term consensus gas price forecast, adjusted for Ontario.

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[38] The debt service coverage ratio that would be required by banks will be affected by the characteristics of the loan including the term, the interest rate and debt payment guarantees that are negotiated as part of the financing. A ratio of 2.0 is reflective of the financing assumptions assumed for the new entrant.

The consensus gas price forecast is the average of forecasts from four separate price projections, including the Energy Information Administration (EIA), the Gas Research Institute (GRI), The WEFA Group (WEFA) and Standard and Poor (S&P).[39] These widely used sources present a broad perspective on the potential changes in commodity fuel markets and to provide an indication of the real escalation projected for gas prices after 2001. Each forecast was equally weighted in an effort to arrive at an unbiased consensus projection of fuel prices. The escalation implicit in the consensus projection was applied to the Union Gas price forecast to derive a projected forecast of gas prices over the life of the project. The following table indicates the assumed gas price forecast.

Table 5-2
Delivered Natural Gas Price Projection [40]
($/MMBtu)

	2001 (Base Price)	2005	2010	2015	2020
Real $2000	4.61	4.41	4.64	4.77	4.88
Real Annual Escalation[41]	--	-1.10%	1.03%	0.55%	0.43%
Nominal $	4.73	4.99	5.94	6.91	7.99

Some baseload gas-fired plants may incur fixed costs to firm natural gas supplies. The EIA projects, however, that as industry restructuring increasingly puts pressure on generators to reduce costs, generating stations will rely on interruptible deliveries and will insure fuel supplies by using oil as a backup fuel.[42] This analysis assumes that plants will not pay reservation charges, rather they will firm fuel supplies by using No. 2 fuel oil during periods of interruption. Thus, firming was not added to the commodity cost of fuel.

5.3 Additional Project Value

The electricity pricing methodology described in this section is based on the assumption that developers would expect to earn an appropriate return on their invested capital in the long-term. This approach does not capture short-term congestion, location or regulation rents. Aberrant

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39 The source forecasts are as follows: 2000 Annual Energy Outlook, EIA; 2000 Baseline Projection, GRI; 2000 Natural Gas Outlook, WEFA; Standard & Poor's World Energy Service U.S. Outlook, Fall-Winter 1999-2000.

40 Note: Gas price projections are lower than Nymex forecasts.

41 Based on a consensus forecast of US gas prices.

42 EIA, Challenges of Electric Power Industry Restructuring for Fuel Suppliers, September 1998, p. 65.

spikes in electricity prices that may occur because of unexpected outages and limitations on transmission capacity also are not taken into account. In addition, we have not assigned any additional value to having plant capacity available when others either have lost capacity or are unable to meet their short-term obligations. Each of these factors could increase the average price of electricity that would be received by the new entrant.

A more elaborate methodology would model the transmission lines and hourly loads. Simulations could be used to analyze a wide range of possible futures that would allow us to estimate whether the site-specific advantages create value during possible short-term disruptions. Such option values can be estimated using existing production cost models that PHB Hagler Bailly runs routinely for clients. However, OPGI's ability to exercise market power would make the results of a production cost model relatively ineffective at forecasting prices unless OPGI's market strategy was incorporated into the model. A quantitative estimation of these potential values is outside the scope of the current assignment and has not been addressed in this report.

5.4 Results

Based on the approaches described above, the first-year fully allocated cost of a new combined cycle is calculated as follows:

Methodology 1: $50.53/MWh

Methodology 2: $48.65/MWh

The detailed pro forma that supports these numbers is presented in Appendix A.

6 A CALCULATED REFERENCE PRICE

As discussed above, approximately 70 percent of total generation in Ontario is expected to be subject to the MPMA rebate. This amount of generation will cost Ontario consumers an average of $38/MWh.

The remaining 30 percent will be purchased by consumers at market prices. For the reasons discussed above, the market price is unlikely to exceed the fully allocated cost of a new combined cycle.

Weighting each price by the proportion of generation to which it would apply results in the following reference prices:

Methodology 1: $41.76/MWh

Methodology 2: $41.20/MWh

Given the concern by market participants that the reference price should be higher rather than lower, Methodology 1 yields the recommended reference price.

APPENDIX A

Pro Forma Analysis of a
New Combined Cycle Gas Turbine

Cash Flow Requirements for a New Combined Gas Turbine
2000-2009

Financial Parameters		
Basis Year for Operational Data		2000
Annual Rate of Inflation	%	2.50%
Long Term Debt Portion of Financing	%	51.00%
Physical/Economic Life of Plant	Years	30
Term of Debt	Years	20
Nominal Required After-Tax Return on Equity	%	13.63%
Project Cost of Debt	%	8.23%
Discount Date		**1/1/2001**

Cost Parameters			
Capital Cost of CC Built in 2000	2000	CAN$/kW	724.25
Property Taxes		%	1.00%
Insurance		%	0.50%
Fixed O&M plus A&G Costs	2000	CAN$/kW-yr	22.89
Variable O&M Costs	2000	CAN$/MWh	2.19

Operational Parameters		
Year of Initial Operation		2001
Plant Capacity	MW	375
Annual Decline of Capacity Factor	%	0.50%
Heat Rate for Plant Built In 2000	Btu/kWh	6,600

			Assumptions	Total	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
Cash Flow Analysis														
Parameters														
Inflation Index (2000 = 1.000)	2000		Index Year		1.000	1.025	1.051	1.077	1.104	1.131	1.160	1.189	1.218	1.249
Ontario Effective Income Tax Rate						36.62%	33.55%	32.58%	31.68%	30.87%	30.12%	30.12%	30.12%	30.12%
Capital Cost														
Initial Capital Cost	2000	CAN$/kW	724											
Total Initial Investment	2000	CAN$	271,594,250											
Total Initial Investment	Nominal	CAN$	278,384,106											
Loan														
BOY Loan Balance	Nominal	CAN$	141,975,894			141,975,894	138,952,691	135,680,577	132,139,060	128,305,957	124,157,263	119,666,993	114,807,023	109,546,916
Loan Payment	Nominal	CAN$		294,251,034		14,712,552	14,712,552	14,712,552	14,712,552	14,712,552	14,712,552	14,712,552	14,712,552	14,712,552
Interest Payment	Nominal	CAN$		152,275,140		11,689,349	11,440,438	11,171,034	10,879,449	10,563,857	10,222,281	9,852,582	9,452,445	9,019,363
Principal Payment	Nominal	CAN$		141,975,894		3,023,203	3,272,113	3,541,517	3,833,102	4,148,695	4,490,270	4,859,969	5,260,107	5,693,189
Loan Balance	Nominal	CAN$				138,952,691	135,680,577	132,139,060	128,305,957	124,157,263	119,666,993	114,807,023	109,546,916	103,853,727
Operations														
Capacity Factor		%	80.0%			80.0%	79.5%	79.0%	78.5%	78.0%	77.5%	77.0%	76.5%	76.0%
Generation		gWh		71,741		2,628	2,612	2,595	2,586	2,562	2,546	2,529	2,520	2,497
Variable O&M	Nominal	CAN$		233,201,847		5,911,866	6,021,790	6,133,515	6,264,178	6,362,454	6,479,711	6,598,854	6,738,315	6,842,883
Natural Gas Price		CAN$/mmBtu				4.73	4.79	4.86	4.92	4.99	5.17	5.35	5.54	5.74
Heat Rate for Plant Built in 2001		Btu/kWh	6,600			6,600	6,600	6,600	6,600	6,600	6,600	6,600	6,600	6,600
Total Fuel Cost		CAN$		3,329,928,898		81,957,342	82,561,733	83,168,310	84,006,550	84,387,823	86,823,737	89,327,199	92,151,723	94,543,735
Total Variable Costs		CAN$		3,563,130,746		87,869,208	88,583,523	89,301,825	90,270,728	90,750,277	93,303,448	95,926,053	98,890,038	101,386,618
Fixed O&M plus A&G		CAN$		386,230,510		8,797,420	9,017,355	9,242,789	9,473,859	9,710,705	9,953,473	10,202,310	10,457,368	10,718,802
Property Tax		CAN$		125,273,601		2,853,437	2,924,773	2,997,892	3,072,840	3,149,661	3,228,402	3,309,112	3,391,840	3,476,636
Insurance		CAN$		62,636,801		1,426,719	1,462,387	1,498,946	1,536,420	1,574,830	1,614,201	1,654,556	1,695,920	1,738,318
Total Fixed Costs		CAN$		574,140,912		13,077,575	13,404,515	13,739,628	14,083,118	14,435,196	14,796,076	15,165,978	15,545,128	15,933,756
Interest		CAN$		152,275,140		11,689,349	11,440,438	11,171,034	10,879,449	10,563,857	10,222,281	9,852,582	9,452,445	9,019,363
Total Cash Expenses		CAN$		4,289,546,797		112,636,132	113,428,476	114,212,487	115,233,295	115,749,331	118,321,805	120,944,614	123,887,610	126,339,736
Class 43 Capital Cost Allowance						0.1500	0.2550	0.1785	0.1250	0.0875	0.0612	0.0429	0.0300	0.0210
Depreciation		CAN$		278,376,487		41,757,616	70,987,947	49,691,563	34,784,094	24,348,866	17,044,206	11,930,944	8,351,661	5,846,163

Cash Flow Requirements for a New Combined Cycle Gas Turbine
2010-2019

Financial Parameters		
Basis Year for Operational Data		2000
Annual Rate of Inflation	%	2.50%
Long Term Debt Portion of Financing	%	51.00%
Physical/Economic Life of Plant	Years	30
Term of Debt	Years	20
Nominal Required After-Tax Return on Equity	%	13.63%
Project Cost of Debt	%	8.23%
Discount Date		**1/1/2001**

Cost Parameters			
Capital Cost of CC Built in 2000	2000	CAN$/kW	724.25
Property Taxes		%	1.00%
Insurance		%	0.50%
Fixed O&M plus A&G Costs	2000	CAN$/kW-yr	22.89
Variable O&M Costs	2000	CAN$/MWh	2.19

Operational Parameters		
Year of Initial Operation		2001
Plant Capacity	MW	375
Annual Decline of Capacity Factor	%	0.50%
Heat Rate for Plant Built In 2000	Btu/kWh	6,600

			Assumptions	Total	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Cash Flow Analysis														
Parameters														
Inflation Index (2000 = 1.000)	2000		Index Year		1.280	1.312	1.345	1.379	1.413	1.448	1.485	1.522	1.560	1.599
Ontario Effective Income Tax Rate					30.12%	30.12%	30.12%	30.12%	30.12%	30.12%	30.12%	30.12%	30.12%	30.12%
Capital Cost														
Initial Capital Cost	2000	CAN$/kW	724											
Total Initial Investment	2000	CAN$	271,594,250											
Total Initial Investment	Nominal	CAN$	278,384,106											
Loan														
BOY Loan Balance	Nominal	CAN$	141,975,894		103,853,727	97,691,799	91,022,539	83,804,176	75,991,502	67,535,584	58,383,462	48,477,815	37,756,604	26,152,679
Loan Payment	Nominal	CAN$		294,251,034	14,712,552	14,712,552	14,712,552	14,712,552	14,712,552	14,712,552	14,712,552	14,712,552	14,712,552	14,712,552
Interest Payment	Nominal	CAN$		152,275,140	8,550,624	8,043,291	7,494,189	6,899,877	6,256,634	5,560,430	4,806,905	3,991,340	3,108,627	2,153,237
Principal Payment	Nominal	CAN$		141,975,894	6,161,928	6,669,260	7,218,363	7,812,675	8,455,918	9,152,122	9,905,647	10,721,212	11,603,925	12,559,314
Loan Balance	Nominal	CAN$			97,691,799	91,022,539	83,804,176	75,991,502	67,535,584	58,383,462	48,477,815	37,756,604	26,152,679	13,593,365
Operations														
Capacity Factor		%	80.0%		75.5%	75.0%	74.5%	74.0%	73.5%	73.0%	72.5%	72.0%	71.5%	71.0%
Generation		gWh		71,741	2,480	2,464	2,454	2,431	2,414	2,398	2,388	2,365	2,349	2,332
Variable O&M	Nominal	CAN$		233,201,847	6,967,811	7,094,708	7,243,386	7,354,492	7,487,420	7,622,397	7,780,703	7,898,579	8,039,821	8,183,188
Natural Gas Price		CAN$/mmBtu			5.94	6.12	6.31	6.50	6.70	6.91	7.11	7.32	7.54	7.76
Heat Rate for Plant Built in 2001		Btu/kWh	6,600		6,600	6,600	6,600	6,600	6,600	6,600	6,600	6,600	6,600	6,600
Total Fuel Cost		CAN$		3,329,928,898	97,260,383	99,576,048	102,221,909	104,361,029	106,832,248	109,357,239	112,112,531	114,304,794	116,853,783	119,453,983
Total Variable Costs		CAN$		3,563,130,746	104,228,194	106,670,756	109,465,295	111,715,521	114,319,668	116,979,636	119,893,233	122,203,372	124,893,604	127,637,171
Fixed O&M plus A&G		CAN$		386,230,510	10,986,772	11,261,441	11,542,977	11,831,552	12,127,340	12,430,524	12,741,287	13,059,819	13,386,315	13,720,972
Property Tax		CAN$		125,273,601	3,563,552	3,652,641	3,743,957	3,837,556	3,933,495	4,031,832	4,132,628	4,235,943	4,341,842	4,450,388
Insurance		CAN$		62,636,801	1,781,776	1,826,320	1,871,978	1,918,778	1,966,747	2,015,916	2,066,314	2,117,972	2,170,921	2,225,194
Total Fixed Costs		CAN$		574,140,912	16,332,100	16,740,402	17,158,912	17,587,885	18,027,582	18,478,272	18,940,229	19,413,734	19,899,078	20,396,555
Interest		CAN$		152,275,140	8,550,624	8,043,291	7,494,189	6,899,877	6,256,634	5,560,430	4,806,905	3,991,340	3,108,627	2,153,237
Total Cash Expenses		CAN$		4,289,546,797	129,110,917	131,454,450	134,118,396	136,203,284	138,603,884	141,018,338	143,640,367	145,608,447	147,901,308	150,186,963
Class 43 Capital Cost Allowance					0.0147	0.0103	0.0072	0.0050	0.0035	0.0025	0.0017	0.0012	0.0008	0.0006
Depreciation		CAN$		278,376,487	4,092,314	2,864,620	2,005,234	1,403,664	982,565	687,795	481,457	337,020	235,914	165,140

Cash Flow Requirements for a New Combined Cycle Gas Turbine
2020-2030

Financial Parameters		
Basis Year for Operational Data		2000
Annual Rate of Inflation	%	2.50%
Long Term Debt Portion of Financing	%	51.00%
Physical/Economic Life of Plant	Years	30
Term of Debt	Years	20
Nominal Required After-Tax Return on Equity	%	13.63%
Project Cost of Debt	%	8.23%
Discount Date		**1/1/2001**

Cost Parameters			
Capital Cost of CC Built in 2000	2000	CAN$/kW	724.25
Property Taxes		%	1.00%
Insurance		%	0.50%
Fixed O&M plus A&G Costs	2000	CAN$/kW-yr	22.89
Variable O&M Costs	2000	CAN$/MWh	2.19

Operational Parameters		
Year of Initial Operation		2001
Plant Capacity	MW	375
Annual Decline of Capacity Factor	%	0.50%
Heat Rate for Plant Built In 2000	Btu/kWh	6,600

			Assumptions	Total	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Cash Flow Analysis															
Parameters															
Inflation Index (2000 = 1.000)	2000		Index Year		1.639	1.680	1.722	1.765	1.809	1.854	1.900	1.948	1.996	2.046	2.098
Ontario Effective Income Tax Rate					30.12%	30.12%	30.12%	30.12%	30.12%	30.12%	30.12%	30.12%	30.12%	30.12%	30.12%
Capital Cost															
Initial Capital Cost	2000	CAN$/kW	724												
Total Initial Investment	2000	CAN$	271,594,250												
Total Initial Investment	Nominal	CAN$	278,384,106												
Loan															
BOY Loan Balance	Nominal	CAN$	141,975,894		13,593,365	0	0	0	0	0	0	0	0	0	0
Loan Payment	Nominal	CAN$		294,251,034	14,712,552	0	0	0	0	0	0	0	0	0	0
Interest Payment	Nominal	CAN$		152,275,140	1,119,187	0	0	0	0	0	0	0	0	0	0
Principal Payment	Nominal	CAN$		141,975,894	13,593,365	0	0	0	0	0	0	0	0	0	0
Loan Balance	Nominal	CAN$			0	0	0	0	0	0	0	0	0	0	0
Operations															
Capacity Factor		%	80.0%		70.5%	70.0%	69.5%	69.0%	68.5%	68.0%	67.5%	67.0%	66.5%	66.0%	65.5%
Generation		gWh		71,741	2,322	2,300	2,283	2,267	2,256	2,234	2,217	2,201	2,191	2,168	2,152
Variable O&M	Nominal	CAN$		233,201,847	8,351,517	8,476,371	8,626,221	8,778,266	8,956,994	9,089,004	9,247,727	9,408,706	9,598,179	9,737,484	9,905,308
Natural Gas Price		CAN$/mmBtu			7.99	8.19	8.39	8.60	8.82	9.04	9.26	9.50	9.73	9.98	10.23
Heat Rate for Plant Built in 2001		Btu/kWh	6,600		6,600	6,600	6,600	6,600	6,600	6,600	6,600	6,600	6,600	6,600	6,600
Total Fuel Cost		CAN$		3,329,928,898	122,440,737	124,271,203	126,468,141	128,697,255	131,317,575	133,252,952	135,579,979	137,940,075	140,717,914	142,760,257	145,220,709
Total Variable Costs		CAN$		3,563,130,746	130,792,255	132,747,574	135,094,362	137,475,521	140,274,569	142,341,956	144,827,707	147,348,782	150,316,093	152,497,742	155,126,017
Fixed O&M plus A&G		CAN$		386,230,510	14,063,997	14,415,597	14,775,987	15,145,386	15,524,021	15,912,121	16,309,925	16,717,673	17,135,614	17,564,005	18,003,105
Property Tax		CAN$		125,273,601	4,561,648	4,675,689	4,792,581	4,912,396	5,035,206	5,161,086	5,290,113	5,422,366	5,557,925	5,696,873	5,839,295
Insurance		CAN$		62,636,801	2,280,824	2,337,844	2,396,291	2,456,198	2,517,603	2,580,543	2,645,056	2,711,183	2,778,962	2,848,436	2,919,647
Total Fixed Costs		CAN$		574,140,912	20,906,468	21,429,130	21,964,858	22,513,980	23,076,829	23,653,750	24,245,094	24,851,221	25,472,502	26,109,314	26,762,047
Interest		CAN$		152,275,140	1,119,187	0	0	0	0	0	0	0	0	0	0
Total Cash Expenses		CAN$		4,289,546,797	152,817,910	154,176,704	157,059,220	159,989,501	163,351,398	165,995,706	169,072,800	172,200,003	175,788,594	178,607,056	181,888,064
Class 43 Capital Cost Allowance					0.0004	0.0003	0.0002	0.0001	0.0001	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000
Depreciation		CAN$		278,376,487	115,598	80,918	56,643	39,650	27,755	19,429	13,600	9,520	6,664	4,665	3,265

Calculation of Required Electricity Prices
2000-2009

		Assumptions	Total	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
Prices Based on Debt Coverage Requirement													
Constant Ratio of EBITDA Over Debt Payment		2.164			2.164	2.164	2.164	2.164	2.164	2.164	2.164	2.164	2.164
Required EBITDA	CAN$		636,807,370		31,840,369	31,840,369	31,840,369	31,840,369	31,840,369	31,840,369	31,840,369	31,840,369	31,840,369
Pre-Tax Profit Requirement	CAN$		206,155,743		-21,606,596	-50,588,017	-29,022,229	-13,823,175	-3,072,354	4,573,881	10,056,842	14,036,263	16,974,843
Projected Income Taxes	CAN$		58,001,207		-7,912,335	-16,973,608	-9,454,396	-4,379,669	-948,340	1,377,653	3,029,121	4,227,722	5,112,823
After-Tax Profit Requirement	CAN$		148,154,537		-13,694,261	-33,614,408	-19,567,833	-9,443,506	-2,124,014	3,196,228	7,027,721	9,808,540	11,862,020
Required Equity Cash Flow	CAN$		148,146,917	-136,408,212	25,040,152	34,101,425	26,582,213	21,507,486	18,076,157	15,750,164	14,098,696	12,900,095	12,014,994
Required Equity Cash Flow After-Tax Nominal IRR on Equity	%			13.63%									
PV Factor				1.0000	0.9386	0.8261	0.7270	0.6396	0.5630	0.4955	0.4360	0.3836	0.3376
PV of Required Equity Cash Flow	CAN$		0	-136,408,212	23,503,419	28,170,778	19,326,343	13,757,150	10,176,002	7,803,482	6,147,726	4,948,901	4,056,689
Required Total Revenues	CAN$		4,774,079,027		132,787,152	133,828,406	134,881,821	136,194,215	137,025,842	139,939,893	142,932,400	146,275,534	149,160,742
Required Average Electricity Price Per MWh	CAN$/MWh				50.53	51.24	51.97	52.67	53.48	54.97	56.51	58.05	59.75
Prices Based on Real Levelized Price													
Levelized Price That Yields Required Nominal IRR on Equity - Nominal	CAN$/MWh				48.65	49.87	51.12	52.40	53.71	55.05	56.42	57.83	59.28
Projected Market Revenues	CAN$		5,043,773,676		127,863,973	130,241,443	132,657,873	135,483,897	137,609,454	140,145,525	142,722,395	145,738,710	148,000,343
Projected Market Income Before Taxes	CAN$		475,850,392		-26,529,775	-54,174,980	-31,246,177	-14,533,492	-2,488,743	4,779,514	9,846,837	13,499,438	15,814,444
Projected Market Income Taxes	CAN$		138,728,725		-9,715,204	-18,177,128	-10,178,878	-4,604,723	-768,198	1,439,590	2,965,867	4,066,031	4,763,311
Projected Market Income After Taxes	CAN$		337,121,667		-16,814,571	-35,997,851	-21,067,299	-9,928,770	-1,720,545	3,339,924	6,880,969	9,433,407	11,051,134
Projected Equity Cash Flow	CAN$		337,114,047	-136,408,212	21,919,841	31,717,982	25,082,746	21,022,222	18,479,626	15,893,860	13,951,944	12,524,962	11,204,107
Required Equity Cash Flow After-Tax Nominal IRR on Equity	%			13.63%									
PV Factor				1.0000	0.9386	0.8261	0.7270	0.6396	0.5630	0.4955	0.4360	0.3836	0.3376
PV of Projected Trajectory Equity Cash Flow	CAN$		0	-136,408,212	20,574,604	26,201,845	18,236,171	13,446,754	10,403,136	7,874,676	6,083,735	4,804,987	3,782,904
Projected Debt Coverage Ratio					1.830	1.920	2.013	2.116	2.204	2.178	2.150	2.128	2.085
Constant Ratio of EBITDA Over Debt Payment		2.164			2.164	2.164	2.164	2.164	2.164	2.164	2.164	2.164	2.164

Calculation of Required Electricity Prices
2010-2019

		Assumptions	Total	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Prices Based on Debt Coverage Requirement													
Constant Ratio of EBITDA Over Debt Payment		2.164		2.164	2.164	2.164	2.164	2.164	2.164	2.164	2.164	2.164	2.164
Required EBITDA	CAN$		636,807,370	31,840,369	31,840,369	31,840,369	31,840,369	31,840,369	31,840,369	31,840,369	31,840,369	31,840,369	31,840,369
Pre-Tax Profit Requirement	CAN$		206,155,743	19,197,431	20,932,457	22,340,946	23,536,828	24,601,170	25,592,144	26,552,007	27,512,009	28,495,828	29,521,992
Projected Income Taxes	CAN$		58,001,207	5,782,266	6,304,856	6,729,093	7,089,292	7,409,872	7,708,354	7,997,464	8,286,617	8,582,943	8,892,024
After-Tax Profit Requirement	CAN$		148,154,537	13,415,165	14,627,601	15,611,853	16,447,535	17,191,298	17,883,790	18,554,542	19,225,392	19,912,884	20,629,968
Required Equity Cash Flow	CAN$		148,146,917	11,345,551	10,822,961	10,398,724	10,038,524	9,717,944	9,419,463	9,130,352	8,841,200	8,544,874	8,235,793
Required Equity Cash Flow After-Tax Nominal IRR on Equity	%												
PV Factor				0.2972	0.2615	0.2301	0.2025	0.1782	0.1569	0.1380	0.1215	0.1069	0.0941
PV of Required Equity Cash Flow	CAN$		0	3,371,366	2,830,471	2,392,616	2,032,802	1,731,936	1,477,460	1,259,962	1,073,775	913,356	774,769
Required Total Revenues	CAN$		4,774,079,027	152,400,662	155,251,527	158,464,576	161,143,775	164,187,619	167,298,277	170,673,830	173,457,475	176,633,050	179,874,094
Required Average Electricity Price Per MWh	CAN$/MWh			61.45	63.01	64.57	66.29	68.00	69.76	71.47	73.34	75.20	77.12
Prices Based on Real Levelized Price													
Levelized Price That Yields Required Nominal IRR on Equity - Nominal	CAN$/MWh			60.76	62.28	63.84	65.43	67.07	68.75	70.47	72.23	74.03	75.88
Projected Market Revenues	CAN$		5,043,773,676	150,702,323	153,446,902	156,662,560	159,065,616	161,940,619	164,859,957	168,283,841	170,833,307	173,888,139	176,988,942
Projected Market Income Before Taxes	CAN$		475,850,392	17,499,092	19,127,832	20,538,930	21,458,669	22,354,171	23,153,824	24,162,017	24,887,841	25,750,917	26,636,839
Projected Market Income Taxes	CAN$		138,728,725	5,270,727	5,761,303	6,186,326	6,463,351	6,733,076	6,973,932	7,277,600	7,496,218	7,756,176	8,023,016
Projected Market Income After Taxes	CAN$		337,121,667	12,228,366	13,366,529	14,352,604	14,995,318	15,621,095	16,179,892	16,884,418	17,391,623	17,994,741	18,613,823
Projected Equity Cash Flow	CAN$		337,114,047	10,158,751	9,561,889	9,139,475	8,586,307	8,147,741	7,715,565	7,460,228	7,007,431	6,626,730	6,219,648
Required Equity Cash Flow After-Tax Nominal IRR on Equity	%												
PV Factor				0.2972	0.2615	0.2301	0.2025	0.1782	0.1569	0.1380	0.1215	0.1069	0.0941
PV of Projected Trajectory Equity Cash Flow	CAN$		0	3,018,705	2,500,669	2,102,878	1,738,727	1,452,093	1,210,201	1,029,490	851,062	708,327	585,103
Projected Debt Coverage Ratio				2.049	2.042	2.042	2.023	2.011	1.998	2.002	1.986	1.978	1.968
Constant Ratio of EBITDA Over Debt Payment		2.164		2.164	2.164	2.164	2.164	2.164	2.164	2.164	2.164	2.164	2.164

Calculation of Required Electricity Prices
2020-2030

		Assumptions	Total	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Prices Based on Debt Coverage Requirement														
Constant Ratio of EBITDA Over Debt Payment		2.164		2.164										
Required EBITDA	CAN$		636,807,370	31,840,369	0	0	0	0	0	0	0	0	0	0
Pre-Tax Profit Requirement	CAN$		206,155,743	30,605,584	-80,918	-56,643	-39,650	-27,755	-19,429	-13,600	-9,520	-6,664	-4,665	-3,265
Projected Income Taxes	CAN$		58,001,207	9,218,402	-24,373	-17,061	-11,943	-8,360	-5,852	-4,096	-2,867	-2,007	-1,405	-984
After-Tax Profit Requirement	CAN$		148,154,537	21,387,182	-56,546	-39,582	-27,707	-19,395	-13,577	-9,504	-6,653	-4,657	-3,260	-2,282
Required Equity Cash Flow	CAN$		148,146,917	7,909,415	24,373	17,061	11,943	8,360	5,852	4,096	2,867	2,007	1,405	984
Required Equity Cash Flow After-Tax Nominal IRR on Equity	%													
PV Factor				0.0828	0.0728	0.0641	0.0564	0.0496	0.0437	0.0384	0.0338	0.0298	0.0262	0.0231
PV of Required Equity Cash Flow	CAN$		0	654,623	1,775	1,094	674	415	256	158	97	60	37	23
Required Total Revenues	CAN$		4,774,079,027	183,539,092	154,176,704	157,059,220	159,989,501	163,351,398	165,995,706	169,072,800	172,200,003	175,788,594	178,607,056	181,888,064
Required Average Electricity Price Per MWh	CAN$/MWh			79.03	67.05	68.79	70.58	72.40	74.31	76.25	78.24	80.25	82.38	84.53
Prices Based on Real Levelized Price														
Levelized Price That Yields Required Nominal IRR on Equity - Nominal	CAN$/MWh			77.78	79.73	81.72	83.76	85.86	88.00	90.20	92.46	94.77	97.14	99.57
Projected Market Revenues	CAN$		5,043,773,676	180,629,628	183,330,007	186,571,019	189,859,501	193,725,104	196,580,253	200,013,180	203,494,891	207,592,872	210,605,822	214,235,582
Projected Market Income Before Taxes	CAN$		475,850,392	27,696,120	29,072,384	29,455,156	29,830,350	30,345,951	30,565,118	30,926,779	31,285,368	31,797,614	31,994,101	32,344,252
Projected Market Income Taxes	CAN$		138,728,725	8,342,071	8,756,602	8,871,893	8,984,901	9,140,200	9,206,214	9,315,146	9,423,153	9,577,441	9,636,623	9,742,089
Projected Market Income After Taxes	CAN$		337,121,667	19,354,049	20,315,782	20,583,263	20,845,449	21,205,751	21,358,905	21,611,633	21,862,215	22,220,173	22,357,478	22,602,163
Projected Equity Cash Flow	CAN$		337,114,047	5,876,282	20,396,700	20,639,906	20,885,099	21,233,506	21,378,333	21,625,233	21,871,735	22,226,837	22,362,143	22,605,429
Required Equity Cash Flow After-Tax Nominal IRR on Equity	%													
PV Factor				0.0828	0.0728	0.0641	0.0564	0.0496	0.0437	0.0384	0.0338	0.0298	0.0262	0.0231
PV of Projected Trajectory Equity Cash Flow	CAN$		0	486,351	1,485,727	1,323,181	1,178,366	1,054,012	933,964	831,475	740,123	661,727	585,931	521,289
Projected Debt Coverage Ratio				1.966										
Constant Ratio of EBITDA Over Debt Payment		2.164		2.164										