NAVIGANT CONSULTING

Ontario Wholesale Electricity Market Price Forecast

For the Period May 1, 2006 through October 31, 2007

Presented to

Ontario Energy Board

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No Warranties or Representations

Some of the assumptions used in the preparation of this wholesale electricity market price forecast, although considered reasonable at the time of preparation, inevitably will not materialize as forecasted as unanticipated events and circumstances occur subsequent to the date of the forecast. Accordingly, actual electricity market prices will vary from the electricity market price forecast and the variations may be material. There is no representation that our Ontario electricity market price forecast will be realized. Important factors that could cause actual electricity market prices to vary from the forecast are disclosed throughout the report.

EXECUTIVE SUMMARY

Navigant Consulting, Inc. (Navigant Consulting or NCI) was retained by the Ontario Energy Board (OEB or the Board) to provide an independent market price forecast for the Ontario wholesale electricity market. This wholesale electricity price forecast will be used to set the price for eligible consumers under the Regulated Price Plan (RPP).

Navigant Consulting used ProSym to develop our hourly Ontario electricity price (HOEP) forecast. Navigant Consulting's Ontario ProSym database reflects the Ontario hourly load shape, all committed new entrant generation, best available information regarding the operating profile of Ontario's hydroelectric generation (baseload and peaking resources), and operating characteristics and fuel prices for Ontario's thermal generation. The sources of our assumptions are reviewed in detail in Chapter 3 of this report.

The table below presents the results of our base case market price forecast produced by ProSym. The on-peak and off-peak prices presented are simple averages, i.e., not load weighted.

Table ES-1: HOEP Forecast ($ CAD per MWh)

Term	Quarter	Calendar Period	On-peak	Off-peak	Average	Term Average
RPP Year	Q1	May 06 - Jul 06	$84.35	$36.42	$59.24	
	Q2	Aug 06 - Oct 06	$88.44	$37.37	$61.69	
	Q3	Nov 06 - Jan 07	$100.99	$39.92	$69.00	
	Q4	Feb 07 - Apr 07	$80.24	$40.19	$59.26	$62.30
Other	Q1	May 07 - Jul 07	$85.72	$38.33	$60.90	
	Q2	Aug 07 - Oct 07	$93.26	$40.76	$65.76	$63.33

Source: NCI
Notes
1) The prices reflect an exchange rate of $1.00 CAD to $0.837 USD
2) On-peak hours include the hours ending at 8 a.m. through 11 p.m. Eastern Standard Time (EST) on working weekdays and off-peak hours include all other hours.

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1. Introduction

Navigant Consulting, Inc. (Navigant Consulting or NCI) was retained by the Ontario Energy Board (OEB or the Board) to provide an independent market price forecast for the Ontario wholesale electricity market. This wholesale electricity price forecast will be used, among other inputs, to set the price for eligible consumers under the Regulated Price Plan (RPP).

This report presents the results of our forecast of the Hourly Ontario Energy Price (HOEP) for the period from May 1, 2006 through October 31, 2007 and describes the major economic and energy market assumptions and inputs for the forecast, as well the source of information. In addition, given that this forecast is based on a specific set of assumptions, the report also evaluates major risk factors in the forecast.

This forecast of the HOEP will be used along with the following to establish the price for the RPP:

- the regulated rate for Ontario Power Generation's (OPG's) prescribed assets,
- the cost of non-utility generation (NUG) contracts administered by the Ontario Electricity Financial Corporation,
- the cost of renewable energy supply (RES) and clean energy supply (CES) contracts administered by the Ontario Power Authority (OPA), and
- the cost of the "Early Mover" and Bruce Power contracts administered by the OPA.

In addition this forecast will be used to determine the value of the OPG non-prescribed asset rebate (OPG Rebate or ONPA Rebate) as part of the RPP.

1.1 Contents of This Report

This report contains five chapters. The first is this Introduction. The second reviews the forecasting methodology, including the framework used for evaluating forecast uncertainty. The next chapter reviews the source of forecast assumptions and reviews key forecast assumptions. The fourth chapter reviews the forecast results. The final chapter discusses the forecast risks.

2. Price Forecasting Methodology

The major factors driving the equilibrium of supply and demand are reflected in the forecast model (ProSym). The model then dispatches generation resources economically to meet hourly load. The output is a set of deterministic prices. If the model is properly specified with best available information it will yield a forecast of expected wholesale electricity prices.

2.1 Overview of the Forecasting Model

Navigant Consulting used ProSym to develop the HOEP forecast. Navigant Consulting's Ontario ProSym database reflects the Ontario hourly load shape, all committed new entrant generation, best available information regarding the operating profile of Ontario's hydroelectric fleet (baseload and peaking resources), and operating characteristics and fuel prices for Ontario's thermal generation. The sources of our assumptions are reviewed in the next chapter. Presented below is a review of ProSym.

ProSym is a detailed chronological model that simulates hourly operation of generation and transmission resources. It dispatches generating resources to match hourly electricity demand, dispatching the cheapest available generation first. The choice of generation is determined by the generator's offer to the market operator -- the Independent Electricity System Operator (IESO), by technical factors such as ramp rates (for fossil resources) or water availability (for hydraulic resources) and by transmission constraints. This dispatch establishes a market-clearing price which each generator located within the same market area receives for its energy output, regardless of its actual offer price.

For most resources, the offer price reflects the incremental cost of the generation. However, some resources have adders reflecting the generator's offer strategy.

Our ProSym model specification includes the entire Eastern Interconnect, so it captures trade between Ontario and its interconnected markets.

Within ProSym, thermal generating resources are characterized according to a range of capacity output levels. Generation costs are calculated based upon heat rate, fuel cost and other operating costs, expressed as a function of output. Physical operating limits related to expected maintenance and forced outages, start-up, unit ramping, minimum up and down time, and other characteristics are respected in the ProSym simulation.

Hydroelectric resources are also characterized in ProSym according to expected output levels, including monthly forecasts of expected energy production. Navigant Consulting has specified ProSym to reflect historical monthly output of Ontario's hydroelectric fleet. The data has been updated to reflect upgrades and capacity additions to Ontario's hydroelectric fleet. ProSym schedules run-of-river hydroelectric production based upon the minimum capacity rating of the unit. The dispatch of remaining hydroelectric energy is optimized on a weekly basis by scheduling hydro production in peak demand hours when it provides the most value to the electrical system.

Offer prices are developed for each unit and show the minimum price the unit owner is willing to accept to cause the unit to operate. For most generation resources, offer prices are composed primarily of incremental production costs. Incremental production post is calculated as each station's fuel price multiplied by the incremental heat rate, plus variable operations and maintenance cost.

The offer price can also include a price mark-up factor taking the bid price above variable production costs. Navigant Consulting uses this factor where appropriate to reflect observed market behaviour where wholesale prices often rise above the underlying cost of production, particularly during times when supply/demand margins are tight. Navigant Consulting assigns price mark-ups to individual generators depending upon the underlying fuel efficiency, production cost and technology type. The specific mark-ups are designed so that offer prices rise above the cost of production as less efficient resources are called upon for power production and as the intersection of supply and demand occurs at higher points on the supply curve. The level of price mark-ups is determined through an iterative approach benchmarking against recent actual wholesale prices, and against observable prices in the forward market. In Ontario given the significant amount of the market represented by OPG's regulated generating assets and the structure of the contracts under the Ministry of Energy's 2,500 MW RFP and recent OPA RFPs[1]. Navigant Consulting believes that the spot market will likely serve as more of a balancing market where in general (excluding storage hydroelectric generating resources) mark-ups are likely to be eliminated with offer strategies based on marginal operating costs.

Market clearing prices reflect the offer of the last generating resource used to meet the next incremental megawatt of demand. Station revenues are based on these market-clearing prices within the market area in which the plant is located.

Navigant Consulting runs ProSym in a mode that establishes market-clearing prices in a specific regional market and in adjacent markets with significant intertie connections. In establishing the market-clearing price, the ProSym simulation takes into account economic import and export possibilities and sets the market-clearing price as the offer price of the marginal generator needed to serve a final increment of demand within the region.[2]

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1 These contracts are structured so that generators' deemed net revenues from participating in the energy market are subtracted from their contracted net revenue requirements or capacity payments to determine the support payments to be made by the OPA. Deemed energy market revenues assume that the generating unit is operating whenever the HOEP is greater than the unit's variable operating costs. This provides a strong incentive for the generator to use a marginal cost based offer strategy, otherwise it will "miss" market revenues that it was deemed to earn in the spot market that are "netted" from its payment under the contract..

2 The Independent Electricity System Operator's (IESO's) Import Offer Guarantee (IOG) rule prevents imports from setting the HOEP. Therefore, there is a difference between our model structure and the Ontario market rules. If the Ontario market were forecast to be in need of significant amounts of energy and capacity and

2.2 Treatment of "OPG Regulated Assets" in the Model Specification

A significant portion of Ontario's generation, i.e., OPG's nuclear and major baseload hydroelectric generating units (Saunders, Beck, and DeCew Falls), have been designated as regulated assets with the price for the output of these plants – up to 1,900 MW in any hour for the hydroelectric resources – currently set under regulation by the Government. While the price for the output of these plants is set under regulation, their value in the Ontario market will be established by the same market dynamics that are in place currently, i.e., a bid-based pool where participating generators receive a uniform price. Specifically, the party responsible for scheduling and ensuring the dispatch of this generation would seek to ensure that this generation is available to the maximum degree possible, particularly during periods when market prices are high and the value of the generation is the greatest. Furthermore, if the scheduling and dispatch of these units does not change given that OPG's regulated assets do not establish the market-clearing price for the vast majority of hours, we expect that the treatment of these generating stations as regulated assets will not affect the HOEP.

2.3 Recognizing Market Pricing Volatility

Experience demonstrates that electricity market prices are inherently volatile. Any wholesale market price forecast should reflect this volatility or, at a minimum, acknowledge it as a source of risk to the price forecast. To determine the volatility of power prices and reflect the uncertainty around any forecast one needs to properly characterize how power prices behave and reflect the shape of the power price probability distribution.

Power prices have a predictable time pattern. Given the optimal dispatch model, lower cost generation resources are used first, so prices can be expected to be lower when demand is low and higher when demand is high. One notion of price volatility, therefore, is the variation of prices over time as a function of demand. The ProSym model will reflect this variation in its hourly price forecasts.

However, each hourly price forecast is itself subject to random (or apparently random) variation. That variation can be measured as the variance of price around the expected hourly value. Variance is a statistical measure of random variation around an expected value. This type of price volatility is not fully captured by the deterministic ProSym model. In determining the RPP price for eligible consumers however, Navigant Consulting and the OEB have developed a methodology that captures, and reflects this potential price volatility. It is referred

relying on imports for this required energy and capacity and if the pricing for imports was significantly different than that for Ontario generation, this difference might result in meaningful differences between our price forecast and actual market prices. However, during the term of this forecast we do not expect the Ontario market to need to rely on imports for significant amounts of energy and capacity and the prices of marginal generation in Ontario and its interconnected markets are not likely to differ significantly. Therefore, we do not believe that this difference between the model structure and market rules is likely to lead to significant differences between forecast prices and actual prices.

to as the stochastic adjustment. A discussion of this methodology and the results of the analysis are presented in the *RPP Price Report (May 06 – Apr 07)*.

3. Short-Term Forecast Assumptions

As discussed above, NCI utilized ProSym as the primary price forecasting tool. The sources of the primary modeling assumptions as well as a review of the key assumptions is presented below.

3.1 Primary Assumptions and Data Sources

Broadly, four classes of primary assumptions underpin our short-term HOEP forecast:

1. Demand forecast
   a. Peak demand
   b. Energy
2. Supply forecast
3. Transmission capabilities and constraints
4. Fuels
   a. Natural gas & oil prices
   b. Coal prices
   c. Hydroelectric resources

Relevant but less important factors include offer strategies, price responsive load and the US-Canada currency exchange rates.[3] The following sections present the data sources for each of the primary assumptions, in the base case scenario which represents the expected forecast.

3.1.1 Demand Forecast

The demand forecast is comprised of two separate components, a peak demand forecast and an energy forecast. The peak demand forecast defines the maximum hourly demand achieved over the forecast period. The energy forecast defines the total (sum over all hours) hourly consumption. Together, the peak demand forecast and the energy forecast define a profile for electricity consumption throughout the forecast period. Both the peak demand forecast and the energy forecast are taken from the IESO's *18-Month Outlook: Ontario Demand Forecast From January 2006 to June 2007,* (December 22, 2005).

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3 The price forecast reflects an exchange rate of $1.00 CAD to $0.837 USD. This is based on the RBC Capital Markets currency forecast, March 28, 2006 (http://www.rbccm.com/0,,cid-23146_,00.html).

The IESO's normal weather energy forecast was used. For the period July through December 2007, NCI has applied the seasonal year over year growth rate to the forecast consumption for that month in 2006.

The IESO's *18-Month Outlook* contains three weather scenarios for peak demand. The "*normal weather*" forecast assumes that each day in a year experiences weather conditions that are representative of normal weather conditions for that day. In effect, the "*normal weather*" forecast assumes that there are never any periods with above average temperatures, or never any periods with below average temperatures. For the purpose of price forecasting this is an inappropriate assumption, given that there will be periods during the year when weather conditions are either above or below the norm. To account for this, the IESO also presents two other forecasts in its *18-Month Outlook*, a "*normal weather + 1 LFU*" (load forecast uncertainty) and an "*extreme weather*" forecast. The "*extreme weather*" forecast assumes the opposite of the "*normal weather*" forecast. That is, each day in the year experiences weather conditions that are consistent with the most extreme weather over the past 30 years. This is also an inappropriate assumption for price forecasting purposes. The third forecast projected by the IESO is a "*normal weather + 1 LFU*" forecast. The term 1 LFU represents one standard deviation of load forecast uncertainty due to weather. This represents a more accurate representation of the expected peak demand over the forecast period, i.e., of expected weather conditions during a typical peak load day.

Table 1 indicates the forecast of monthly energy consumption and peak demand that was used from the IESO. Peak demand is consistent with the IESO's "*normal weather + 1 LFU*" forecast, and energy is consistent with the IESO's "*normal weather*" forecast.

Table 1: Forecast Monthly Energy Consumption and Peak Demand

		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2006	Energy (TWh)		N/A		12.2	12.2	12.5	13.6	13.6	12.4	12.7	13.0	14.0
	Peak Demand (MW)				21,786	22,219	25,223	25,688	25,250	25,000	21,765	23,666	24,837
2007	Energy (TWh)	14.6	13.1	13.7	12.3	12.4	12.7	13.8	13.8	12.6	12.8	N/A	
	Peak Demand (MW)	25,524	24,758	23,919	22,063	22,576	25,578	26,055	25,610	25,356	22,004		

Source: IESO, 18-Month Outlook, Ontario Demand Forecast, December 22 2005

3.1.2 Supply Assumptions

The existing generation capacity assumptions are consistent with the IESO's *18-Month Outlook* (dated December 22, 2005). No coal plant retirements are expected during the forecast period. Bruce-A Units 1 & 2 are assumed not to return to service in this forecast horizon given the estimated time required to refurbish the units.

In addition to the existing supply resources, there are several RES projects and CES projects that are expected to come on-line during the forecast horizon. The IESO's *18-Month Outlook* formed the basis for the new supply assumptions. Navigant Consulting worked with the OEB and the OPA to further refine and expand the assumptions in the IESO outlook including updated commercial in-service dates for the various projects. Table 2 indicates those projects that were assumed to begin commercial operation prior to the end of the forecast period and included in the model specification.

Three facilities, the Glen Miller Hydroelectric, Eastview Landfill Gas, and GTAA Cogeneration facility are already in-service.

Table 2: Generation Capacity Additions

Project Name	Resource Type	Capacity (MW)	In-service date
Essex Power	Oil	3	Q1-2006
Melancthon Grey Wind Project I	Wind	68	Q1-2006
Erie Shores Wind Farm	Wind	99	Q2-2006
EPCOR Kingsbridge Wind Project I	Wind	40	Q2-2006
Loblaw Properties DR Project	DR	10	Q2-2006
Prince Wind Farm (Phase 1)	Wind	99	Q3-2006
Blue Highlands Wind	Wind	50	Q3-2006
Hamilton Digester Cogen Project	Cogen	2	Q3-2006
Leader Wind Power Project A	Wind	101	Q4-2006
Leader Wind Power Project B	Wind	99	Q4-2006
Trail Road Landfill	Biomass	5	Q1-2007
Melancthon Grey Wind Project II	Wind	132	Q1-2007
Goreway Station Peak	SCGT	525	Jun-07

Source: OPA, IESO, NCI

3.1.3 Outages

Generator outages happen for two reasons: planned outages for scheduled maintenance and forced outages for unplanned maintenance. The IESO provided us with its scheduled outage schedule by capacity (fuel) type, on a weekly basis through the end of 2007. We used information from this outage schedule to adjust our standard maintenance outage schedule that is reflected in our model specification.

ProSym includes a database of forced outages by unit type expressed as a percentage of time each unit would experience a forced outage. This database is based on empirical data and historical information on Ontario generating units.

3.1.4 Offer Strategies

Consistent with our observations of how the HOEP has been established, we assume that generators will offer their capacity into the IESO market at their variable cost (fuel cost plus variable operations & maintenance cost), with no provision for bid adders. For units where there was uncertainty regarding the likely offer strategy, Navigant Consulting used the daily generator disclosure reports, an assumed market supply curve and the HOEP to infer offer strategies for the unit.[4]

As discussed in Section 2.1, the Clean Energy Supply (CES) contract provides a strong incentive for generators to offer their electricity into the market at their marginal operating costs. Given the Ministerial Directive[5], Navigant Consulting expects that the Early Mover contracts have a similar incentive.

The recent Board decision to grant Lennox GS Reliability-Must-Run (RMR) status is not expected to effect the bidding behaviour of Lennox materially. OPG indicated that the financial provisions of the RMR contract will have no effect on its offer strategy. The Board decision explicitly states that the RMR contract obliges OPG to "offer into the IESO-administered markets the maximum amount of energy and operating reserve from Lennox in a commercially reasonable manner". By definition, "[I]n a commercially reasonable manner" means that over a sustained period of time OPG will offer each Lennox unit at no less than its variable costs taking into account all necessary operational factors.

In addition to the Lennox RMR contract, the recent OPA sponsored forward auction is also not expected to materially change the bidding behaviour of OPG and Bruce Power.

3.1.5 Price Responsive Load

Our assumptions regarding the amount of price responsive load reflect the information reported by the IESO regarding the amount of price responsive load participating in the Operating Reserve Market and the Hour Ahead Market.

3.1.6 Transmission Capabilities and Constraints

Given that the HOEP is based on a uniform price which does not reflect transmission congestion within Ontario, we do not reflect internal Ontario transmission constraints in this model specification. The transfer capabilities of transmission interconnections with adjacent markets are from the IESO *18-Month Outlook*, differentiated by season and direction of flow. Table 3 indicates the assumed ratings of Ontario's interconnections with adjacent markets based on the information presented in the IESO's *18-Month Outlook*.

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[4] These units included Lennox and the coal units.

[5] http://www.powerauthority.on.ca/Storage/19/1457_Minister_of_Energy_letter_regarding_Contracts_with_Certain_Generation_Facilities_REVISED.pdf

Table 3: Ontario Interconnection Limits

Interconnection	Flows Out of Ontario (MW)	Flows Into Ontario (MW)
Manitoba		
Summer	263	331
Winter	275	343
Minnesota	140	90
Michigan		
Summer	1,550	1,250
Winter	1,700	1,400
New York East	400	400
New York West		
Summer	1,300	1,300
Winter	1,950	1,650
Quebec South		
Summer	617	1,498
Winter	637	1,498
Quebec North		
Summer	95	65
Winter	110	84

Source: IESO, 10-Month Outlook, December 22, 2005

3.1.7 Fuel Prices

Given the uncertainty associated with fuel price forecasts, Navigant Consulting typically relies on liquid financial and physical markets to specify the underlying fuel forecasts we use in power market modeling, unless our clients derive their own forecasts. Since we forecast prices in US dollars, we specify fuel prices within the model in US dollars.

Natural Gas and Fuel Oil

For short-term forecasts, we use the futures prices as reported publicly on the NYMEX website in US$/MMBtu. Sufficient liquidity exists through the end of the forecast period to justify this source. To reduce the volatility associated with taking a snap-shot of future prices on a single day, an average of settlement prices over the past 20 trading days is used. This is similar to the process that Enbridge Gas Distribution and Union Gas use in determining forecast natural gas prices as part of their quarterly rate adjustment mechanism (QRAM) applications to the OEB.[6]

To these futures prices, we apply a basis differential. For natural gas this basis differential is from Henry Hub to the Dawn trading hub in southwestern Ontario. This basis differential is based on the historical relationship between futures prices for delivery at Henry Hub and Dawn. Finally, we apply a local delivery charge to represent costs paid to the gas utility to deliver the gas from Dawn to individual generator locations such as Kingston and Sarnia.

6 NYMEX future prices averaged over 20 day trading period from February 9, 2006 to March 9, 2006.

For residual and distillate oil we also add a basis differential from New York Harbour to Kingston to reflect delivery at Lennox GS. Since Lennox operates as a dual-fuel facility, and we believe it has an environmental constraint on the number of oil-fired hours, we use a blend of natural gas and residual oil price, based on our judgement of when (which months) the facility is likely to burn oil and gas. Natural gas and fuel oil price assumptions are presented in Table 4 below. All prices are in US dollars per MMBtu. The forecast average Henry Hub natural gas price for the twelve months commencing May 2006 is USD $8.69 / MMBtu. The forecast average price over the entire 18-month period is USD $8.64 / MMBtu.

Table 4: Natural Gas and Fuel Oil Prices

Year	Natural Gas @ Henry Hub	#6 Residual Oil @ Southern Ontario	#2 Fuel Oil @ Southern Ontario
May-06	$7.30	$7.82	$12.79
Jun-06	$7.46	$7.91	$12.96
Jul-06	$7.61	$7.98	$13.08
Aug-06	$7.72	$8.03	$13.18
Sep-06	$7.80	$8.07	$13.26
Oct-06	$7.90	$8.11	$13.33
Nov-06	$8.90	$8.14	$13.38
Dec-06	$9.83	$8.16	$13.42
Jan-07	$10.46	$8.18	$13.46
Feb-07	$10.47	$8.20	$13.49
Mar-07	$10.28	$8.21	$13.51
Apr-07	$8.57	$8.22	$13.53
May-07	$8.39	$8.23	$13.54
Jun-07	$8.45	$8.23	$13.54
Jul-07	$8.52	$8.23	$13.54
Aug-07	$8.59	$8.23	$13.54
Sep-07	$8.61	$8.23	$13.54
Oct-07	$8.68	$8.23	$13.54

Source: Henry Hub natural gas prices based on NYMEX futures. #2 Fuel Oil and #6 Fuel Oil prices derived from NYMEX futures for light sweet crude and historical relationship between crude and respective fuel oils. Delivery to Southern Ontario for fuels based on Navigant Consulting estimates.

3.1.8 Coal Prices

A 2004 study entitled *Cost Benefit Analysis: Replacing Ontario's Coal Fired Electricity Generation* was prepared by DSS Management Consultants Inc. and RWDI Air Inc. for the Ontario Ministry of Energy. This study provides site specific fuel costs for OPG's coal-fired facilities.

The following five steps were taken to project the prices presented in the study for 2006 to 2007:

1. Prices in the report were provided in 2004 Canadian dollars and hence converted to U.S. dollars based on the average 2004 USD/CAD exchange rate.
2. Delivery and transportation costs were assumed to represent 40% of the total cost. This portion of the total cost was adjusted for inflation through 2007.[7]
3. Of the remaining 60%, representing the commodity cost, half was assumed to be secured through long term contracts and hence subject to a fixed price through 2007.
4. The remaining half of the commodity cost was assumed to be procured on the spot market, and hence subject to fluctuating commodity prices.
5. Finally, the total delivered site specific price was developed by aggregating the fixed, variable and delivery costs for each of the facilities.

The resulting delivered coal prices for the four coal-fired generation plant (five coal types) in Ontario are presented in Table 5, all prices are presented in US dollars per MMBtu.

Table 5: Ontario Delivered Coal Price Outlook

Year	High Sulfur Bituminous - Lambton 3 & 4	Low Sulfur Bituminous - Lambton 1 & 2	Nanticoke (Blend of low sulfur bituminous and Powder River Basin coal)	Low Sulfur Lignite - Atikokan	Low Sulfur Lignite - Thunder Bay
2006	$2.26	$2.97	$2.19	$1.46	$1.47
2007	$2.21	$2.91	$2.19	$1.44	$1.45

Source: NCI

To verify the accuracy of this approach we compared our forecast to estimated prices based on the existing offer strategies for OPG's coal fleet as derived from the IESO's Daily Generator Disclosure Reports (and applying the unit heat rates). The results indicate a close alignment of the two approaches.

3.1.9 Hydro Resources

Our ProSym specification for Ontario includes a detailed specification of the monthly average hydroelectric output by major hydro unit. In our base case, we assume a normal hydroelectric resource level.

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[7] The consumer price index for transportation related goods and services escalated at twice that of the all-items consumer price index, hence the transportation related index was used to adjust these costs for inflation.

4. Review of Forecast Results

Table 6 presents the results of our base case market price forecast produced by ProSym. The on-peak and off-peak prices presented are simple averages, i.e., not load weighted.

The seasonal price distribution is reasonably reflective of the seasonal pattern of prices that we would expect given that the highest loads are experienced in the summer and winter months and lower loads are experienced in the "shoulder months" of April, May October and November. An additional factor contributing to the seasonal price pattern is the typical output profile of Ontario's hydroelectric generation. September is generally the lowest hydro output month, with May and June representing the highest output based on the spring freshet. [8] In recent years scheduled nuclear and coal maintenance outages have reduced the price impact of lower demand in the shoulder seasons and the spring freshet.

Table 6: HOEP Forecast (CAD $ per MWh)

Term	Quarter	Calendar Period	On-peak	Off-peak	Average	Term Average
RPP Year	Q1	May 06 - Jul 06	$84.35	$36.42	$59.24	
	Q2	Aug 06 - Oct 06	$88.44	$37.37	$61.69	
	Q3	Nov 06 - Jan 07	$100.99	$39.92	$69.00	
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	Q2	Aug 07 - Oct 07	$93.26	$40.76	$65.76	$63.33

Source: NCI

Notes

1) The prices reflect an exchange rate of $1.00 CAD to $0.837 USD

2) On-peak hours include the hours ending at 8 a.m. through 11 p.m. Eastern Standard Time (EST) on working weekdays and off-peak hours include all other hours.

Current 24 x 7 forward contract prices are higher than the wholesale prices presented in this report. The difference represents the premium imbedded in forward market contracts, which may reflect the relative lack of liquidity in the Ontario forward electricity market.

Forecast electricity prices for May through October 2007 are higher than in 2006 primarily as a result of higher forecast natural gas prices.

This price forecast is based on market fundamentals and reflects the assumptions specified in ProSym. To the degree that actual market variables (fuel prices, hourly loads and generator availabilities) are different than our forecast assumptions, market prices are likely to differ from our forecast. As an example of the variability of electricity prices over time, Figure 1 presents

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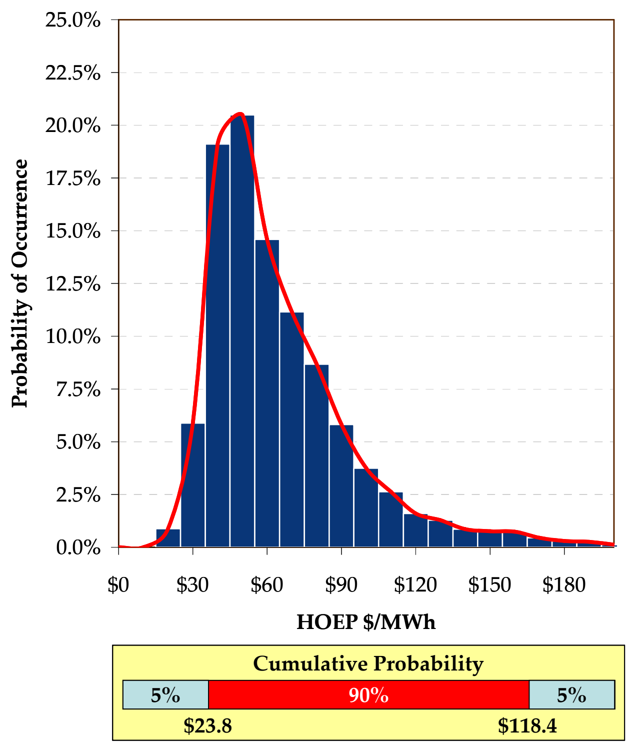
[8] Freshet is the period during which melted snow causes the rise or overflowing of streams in Ontario.

the distribution of the hourly HOEP since market opening. Figure 2 presents the distribution of monthly average prices since market opening. The HOEP is captured on the x-axis and the number of times that the HOEP occurred is reflected in the height of the bars. A key takeaway from these curves is both are skewed to the right, indicating that the average value is higher than the median or 50% percentile value.

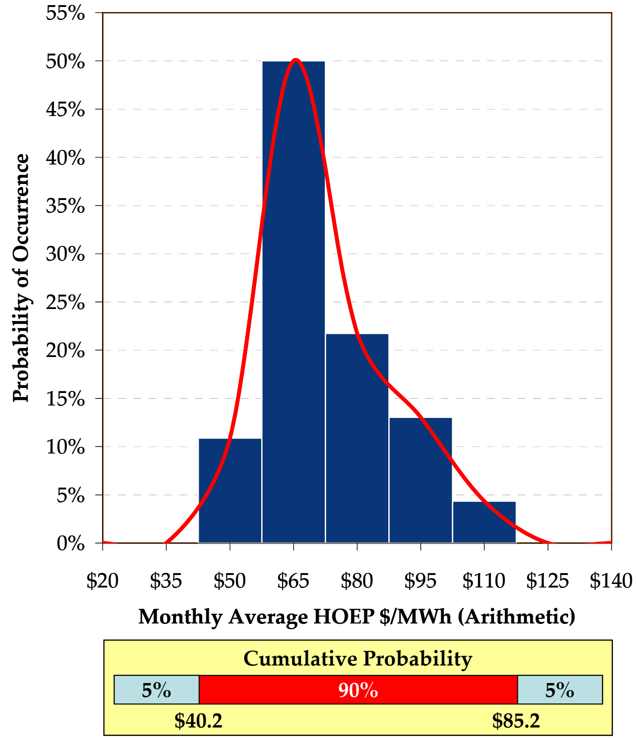
Not surprisingly, the hourly price distribution is significantly more skewed to the right than the monthly price distribution, reflecting the averaging that occurs for the monthly prices. While not as skewed as the distribution of hourly prices, Figure 2 demonstrates that even the distribution of monthly prices is skewed to the right.

Figure 1: Historic Distribution of Hourly HOEP



Source: NCI analysis of IESO data (5/1/02 to 2/28/06)

Figure 2: Historic Distribution of Monthly Average HOEP



Source: NCI analysis of IESO data (5/1/02 to 2/28/06)

5. Assessment of Forecast Risks

As discussed above, the foundation of our HOEP forecast is a market fundamentals analysis which is performed using ProSym. ProSym is a deterministic forecast developed using single point forecasts for each of the determinants of price, and that the potential exists for considerable variability in each of these assumptions. In setting the RPP price, Navigant Consulting and the OEB have used a statistical analysis to evaluate the uncertainty around this deterministic market price forecast and the impact on the RPP price. We believe that this probability analysis allows the OEB to adequately evaluate forecast risks when determining the RPP price. In this chapter we will review the factors that present the greatest forecast risk and assess, in qualitative terms, the degree to which the forecast has addressed them.

Navigant Consulting believes that there are three major risks that an electricity price forecast will not be realized. These stem from differences between forecast and actual: (1) load; (2) fuel prices; and (3) generator availabilities. Each of these forecast risks are assessed below.

5.1 Load Forecast Risk

As discussed, the energy and peak demand forecasts used by Navigant Consulting were developed by the IESO. The energy consumption forecast is based on a forecast of economic activity in Ontario and the assumption that weather conditions will be "normal", i.e., reflective of 30-year average weather over the entire forecast period. To the degree that this economic forecast is wrong or weather conditions depart significantly from normal, as was experienced in the summer of 2005, energy consumption would be expected to vary from the forecast assumption.

In addition, various random elements to the forecast will cause actual loads to vary from our forecast, e.g., consumer behaviour, etc. For our short-term forecast, Navigant Consulting believes that the greatest source of load forecast risk is weather. The IESO indicates that a 1°C increase when the temperature is above 16°C results in approximately a 380 MW increase in the daily peak demand. The IESO's December 2005 18-Month Outlook forecasts a normal weather summer peak of 24,232 MW and an extreme weather peak of 27,407 MW, reflecting how load is forecast to increase under more extreme weather conditions. The variability in loads was specifically considered in the analysis which is reviewed in the companion report, *RPP Price Report (May 06 – Apr 07)*. Analysis of historical price and demand levels clearly demonstrates that load variability is a major contributor to spot market price volatility. Therefore, Navigant Consulting believes that this risk has been considered in our price forecasting approach.

5.2 Fuel Price Forecast Risk

The fuel prices used by Navigant Consulting for this forecast were largely based on the NYMEX futures prices. While we believe that the NYMEX futures represent an appropriate fuel price outlook, as with any forecast there is a significant degree of risk that forecast fuel prices will not be realized.

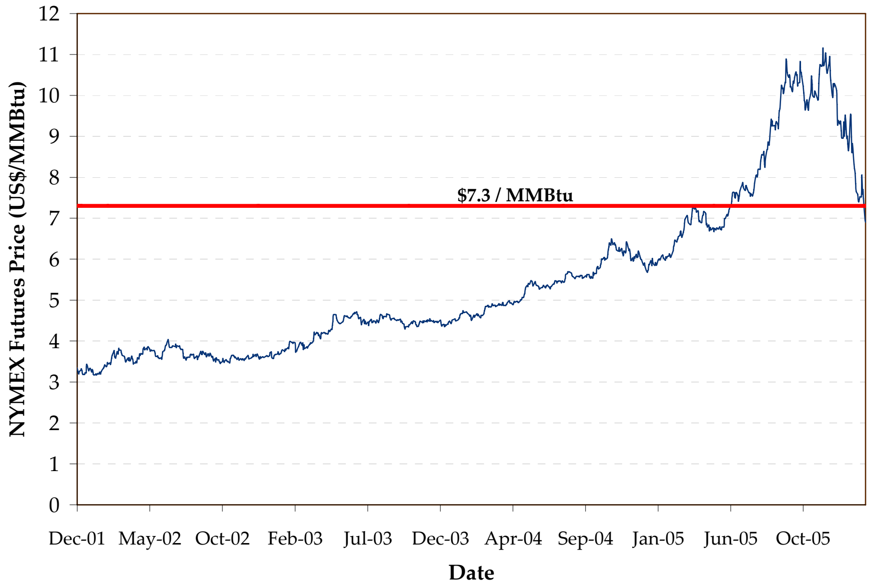
In general, the fuel price that is subject to the most uncertainty is natural gas. Currently Ontario has a relatively limited amount of natural gas-fired generation that is likely to set the HOEP, however natural gas-fired plants do set the HOEP a considerable amount of time and the amount of natural gas-fired generation in the Ontario market will grow over time. The largest natural gas facilities include Lennox (2,140 MW) which is also capable of burning residual oil, the TransAlta Sarnia project (575 MW), the Brighton Beach project (570 MW) and the GTAA Cogeneration Facility (117 MW). However, there is also a considerable amount of natural gas-fired generation in interconnected markets, i.e., primarily New York and Michigan. While generation from these markets cannot set the HOEP under the IESO's Intertie Offer Guarantee rule, it nonetheless has an influence on Ontario market prices.

The most obvious risk associated with natural gas prices is the inherent price volatility of the commodity itself. Natural gas prices are very closely correlated to crude oil prices, and the relative instability of world oil and natural gas markets has led to an increase in the volatility of the commodity price. While this is not captured by the ProSym model, an effort is made to account for a portion of this volatility when setting the RPP price.

When using futures prices for forecasting purposes, the point in time when the natural gas price outlook is cast is another source of risk. To minimize the RPP exposure to this risk, NCI and the OEB have used an average of settlement prices for future contracts over a 20 trading day period.

Figure 3 illustrates the trend in forward prices for natural gas for May 2006 delivery since the end of 2001 and Navigant Consulting's assumption used in the ProSym forecast was based on an average of settlement prices over the most recent 20 day period. This averaging approach mitigates some of the short-term volatility in natural gas prices. Nonetheless, there is a risk that the natural gas price forecast will be wrong, leading to higher or lower electricity prices than forecast.

Figure 3: Historical May 2006 Forward Prices (US$/MMBtu)



Source: NYMEX

Lennox is the only major Ontario generator which burns oil, but generally residual oil is not its primary fuel. Furthermore, there is a relatively limited amount of oil-fired generation in Ontario's interconnected markets. Therefore, Ontario electricity market prices are not significantly influenced by oil prices.

Coal-fired generation establishes the HOEP approximately 50% of all hours, particularly during off-peak hours. Historically, coal prices have been much less volatile than either natural gas or oil prices. This is apparent in Figure 4, where the trend in forward prices for natural gas for May 2006 delivery are compared to the trend in forward prices for Central Appalachian coal for May 2006 delivery. Navigant Consulting expects that this will continue to be the case.

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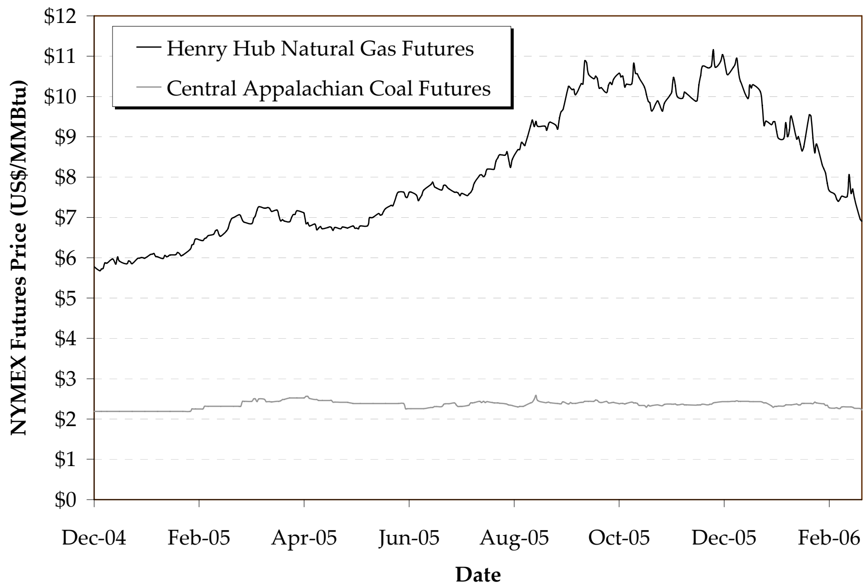
Figure 4: Historical Central Appalachian Coal Prices (US$/MMBtu)

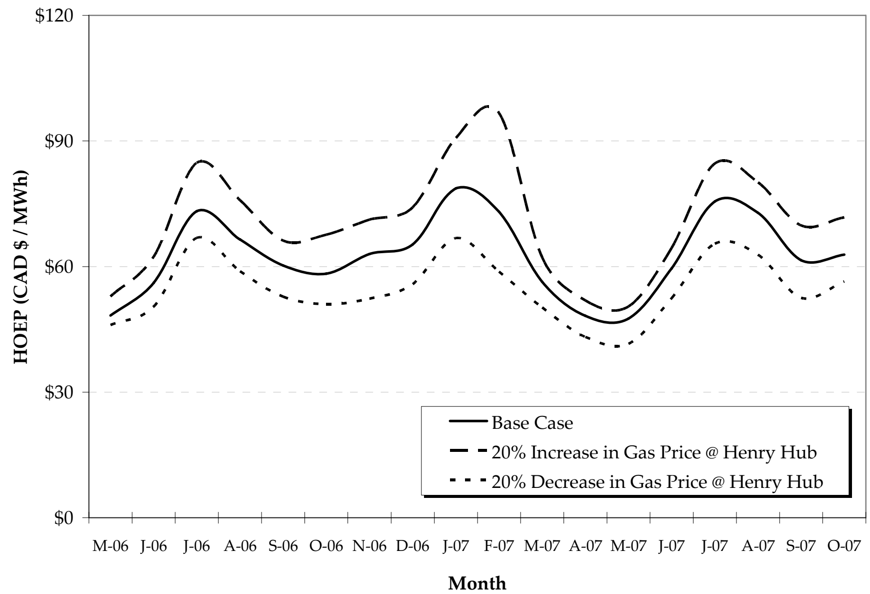


Source: NYMEX

Based on this assessment and the experience of the late summer and fall of 2005, Navigant Consulting believes that the most significant fuel price forecast risk remains natural gas. A cold winter or hot summer that increases the demand for natural gas-fired generation, could result in significant increases in natural gas prices. Conversely, a warm winter or cool summer should result in a softening of near term natural gas prices, such as was witnessed in January and February of 2006.

Therefore, we evaluated the impact of a ± 20% change in Henry Hub natural gas prices on the HOEP using ProSym. The results of this analysis are shown in Figure 5 which shows the monthly average HOEP for a base case as well as high and low natural gas price sensitivities. This analysis indicated that the HOEP increased by an average of about 13% when natural gas prices were assumed to be 20% higher than our forecast and decreased by slightly less -- an average of 12.5% -- when natural gas prices were assumed to be 20% lower than our forecast.

Figure 5: Comparison of Monthly Average HOEP with ±20% Change in Henry Hub Gas Price



Source: NCI

5.3 Generator Availability Price Risks

The third major source of electricity price forecast risk pertains to the availability of Ontario generation. ProSym reflects random generator forced outages and as such this risk is reflected in our model to the degree that the forced outage rates that we have specified in ProSym are reliable. Changes in the availability of Ontario's nuclear fleet are likely to have the most dramatic impact on market prices. A 2% change in capacity factor for Ontario's nuclear fleet results in a 2 TWh change in the availability of low variable cost energy from nuclear capacity. This change in nuclear output is most likely to affect the requirements for Ontario fossil generation. Table 7 contrasts our capacity factor assumptions for Ontario's nuclear fleet with recent experience.

Table 7: Comparison of Historical Nuclear Capacity Factors with Forecast Values

	1999	2000	2001	2002	2003	2004	2005	RPP Year
Actual Capacity Factor	81.3%	79.3%	83.4%	82.5%	80.1%	80.4%	81.6%	
Forecast Capacity Factor								82.7%

Source: NCI analysis of IESO generator disclosure reports and ProSym market modeling results.
Note: RPP Year refers to the period May 06 through April 07 inclusive, one full calendar year.