Ontario Wholesale Electricity Market Price Forecast

For the Period November 1, 2008 through April 30, 2010

Presented to

Ontario Energy Board

October 15, 2008

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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, as one of a number of inputs, to set the price for eligible consumers under the Regulated Price Plan (RPP).

Navigant Consulting used a statistical model of the Ontario electricity market to develop our hourly Ontario electricity price (HOEP) forecast. Navigant Consulting's Ontario model draws on our Ontario database, which 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. Our assumptions and their sources are reviewed in detail in Chapter 3 of this report.

The table below presents the results of our base case market price forecast. 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	Nov 08 - Jan 09	$60.70	$40.04	$49.47	
	Q2	Feb 09 - Apr 09	$60.80	$41.79	$50.49	
	Q3	May 09 - Jul 09	$62.17	$34.32	$47.17	
	Q4	Aug 09 - Oct 09	$68.50	$41.14	$53.54	$50.16
Other	Q1	Nov 09 - Jan 10	$65.12	$42.12	$52.63	
	Q2	Feb 10 - Apr 10	$59.37	$39.58	$48.62	$50.66

Source: NCI
Notes
1) The prices reflect an exchange rate of $1.00 CAD to $0.946.
2) On-peak hours include the hours ending at 8 a.m. through 11 p.m. Eastern 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 November 1, 2008 through April 30, 2010 and describes the major economic and energy market assumptions and inputs for the forecast, as well the sources of information. In addition, given that this forecast is based on a specific set of assumptions, the report 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 payment amounts 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),
- the cost of renewable energy standard offer program (RESOP) contracts administered by the Ontario Power Authority,
- the cost of the "Early Mover" and Bruce Power contracts administered by the OPA; and
- the balance in the variance account held by the OPA.

This forecast will also be used to determine the estimated value of the OPG non-prescribed asset rebate (OPG Rebate or ONPA Rebate) and the Global Adjustment as part of the RPP price.

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 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 our statistical forecast model. The model draws on the history of the Ontario electricity market to determine the relationship between the drivers of market prices and the resulting market prices. This relationship is then extended forward to produce a forecast of expected wholesale electricity prices.

2.1 Overview of the Forecasting Model

Navigant Consulting used our statistical price forecasting model to develop the HOEP forecast. Navigant Consulting's Ontario electricity database reflects 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 brief review of our electricity price forecasting model.

The Ontario electricity market features a mandatory competitive wholesale pool. Any generator wishing to supply electricity to the Ontario market must offer its output to the system operator – the Independent Electricity System Operator (IESO) – as a series of hourly price/quantity pairs. The IESO then chooses the least-cost combination of generation resources which can meet the demand in each hour, subject to technical factors such as ramp rates (for fossil resources) and to transmission constraints. The cost of the most expensive generation dispatched then becomes the market-clearing price which each generator located within the same market area (i.e., Ontario) receives for its energy output, regardless of its actual offer price.

The hourly electricity price in Ontario is therefore determined by the interaction of supply and demand as reflected in the information provided to the IESO. A statistical model will represent these factors.

The Navigant Consulting statistical model was developed using our extensive historical database for the Ontario electricity market. The data include a complete history of HOEP, historical electricity output by fuel type of plants in Ontario and historical electricity demand in Ontario. The database also includes information on market prices for the important fuels (natural gas, coal, and uranium) used for electricity generation in Ontario. In the development of the model, all of these factors were considered. The model was selected as that which best represents the actual history of Ontario electricity prices.

The model considers HOEP to be determined by several important factors.

- Hourly demand for electricity is an important determinant of demand, as noted above. The demand variable included in the model is the total energy demand over the time period.

- The amount of nuclear and hydroelectric energy available to the Ontario market has a strong influence on the hourly electricity price, due to their low operating costs. The more such low-cost energy is available, the less the IESO has to rely on relatively high-cost sources like natural gas generation. The availability of these two forms of low-cost energy is treated in the model as a determinant of electricity price.

- The price of natural gas is also an important determinant of electricity price in Ontario, because as noted it is likely to be the marginal fuel (that is, the resource that sets the market-clearing price) in times when supplies from lower-priced resources (hydroelectric, nuclear, and coal) are insufficient. Even though, in the current Ontario system, natural gas is on the margin relatively infrequently, there is a significant and growing fleet of natural-gas fired generators. Natural gas is also important in setting the price in neighboring markets, which can influence prices in Ontario. Therefore, natural gas prices have a strong role in explaining HOEP and the model includes the price of natural gas as a determinant of the Ontario electricity price. With over 2,500 MW of new gas-fired generation scheduled to come into service by the first quarter of 2009, gas prices are expected to increase in importance in explaining electricity prices.

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. The price for the output of these plants – up to 1,900 MW in any hour for the hydroelectric resources – has been set under regulation by the Government. The authority to set these payment amounts was recently transferred to the Ontario Energy Board. However, a final decision has not yet been issued by the Board. As a result, no assumptions have been made in this forecast regarding what the Board may decide; i.e., the status quo has been used including the 1,900 MW incentive mechanism. While the price for the output of these plants is regulated, 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 operating this generation would seek to ensure that it 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.

However, each price forecast is itself subject to random (or apparently random) variation. That variation can be measured as the variance of price around the expected value. Variance is a statistical measure of random variation around an expected value. This type of price volatility is not fully captured by the statistical model. Therefore, in determining the RPP price for eligible consumers, Navigant Consulting and the OEB have developed a methodology that captures and reflects this potential price volatility. It is referred to as the stochastic adjustment. A discussion of this methodology and the results of the analysis is presented in the *RPP Price Report (November 08 –October 09)*.

3. Short-Term Forecast Assumptions

As discussed above, NCI utilized our statistical model 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, three classes of primary assumptions underpin our short-term HOEP forecast:

1. Demand forecast
2. Supply forecast
3. Fuel Prices

The forecast U.S. - Canada currency exchange rate[1] also influences the short term HOEP forecast indirectly by affecting the price of fuel in Ontario and the price of electricity in neighbouring U.S. markets. 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 an energy forecast for each month over the forecast period. The energy forecast defines the total (sum over all hours) hourly consumption in each month. The energy forecast is taken from the IESO's *18-Month Outlook: An Assessment of the Reliability of the Ontario Electricity System From October 2008 to March 2010,* (September 23, 2008).

The IESO's forecast provides energy consumption by week. This is converted to monthly energy consumption for use in the present forecast. For the energy forecast in April, 2010, NCI has applied the seasonal year over year growth rate to the forecast consumption for the corresponding weeks in 2009.

The IESO's *18-Month Outlook* bases the energy forecast on *"normal weather"*. The "*normal weather*" forecast assumes that each day in a year experiences weather conditions that are representative of normal weather conditions for that day.

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1 The price forecast reflects an exchange rate of $1.00 CAD to $0.946 USD, which was the average exchange rate in September 2008.

Table 1 shows the forecast of monthly energy consumption that was used from the IESO. Energy consumption is consistent with the IESO's "*normal weather*" forecast and reflects load reduction due to conservation initiatives over the forecast horizon.[2].

Table 1: Forecast Monthly Energy Consumption and Peak Demand

		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2008	Energy (TWh)											12.4	13.3
	Peak Demand (MW)											22,258	23,331
2009	Energy (TWh)	13.9	12.5	13.0	11.5	11.7	12.0	13.1	13.0	11.5	12.0	12.4	13.2
	Peak Demand (MW)	23,991	23,517	22,532	20,362	20,549	24,377	25,322	24,582	22,420	20,218	22,091	23,104
2010	Energy (TWh)	13.8	12.5	12.9	11.5								
	Peak Demand (MW)	23,377	23,109	21,983	20,052								

Source: NCI, based on IESO, *18-Month Outlook: An Assessment of the Reliability of the Ontario Electricity System* (September 23, 2008)

3.1.2 Supply Assumptions

The existing generation capacity assumptions are generally consistent with the IESO's *18-Month Outlook* (dated September 23, 2008), except that some of the in-service dates have been updated based on information from the Ontario Power Authority. No coal plant retirements are expected during the forecast period. Bruce A Unit 2 is expected to return to service in the fourth quarter of 2009, according to the IESO. Unit 1 is also being refurbished, and is expected to return to service in the first quarter of 2010.

In addition to the existing supply resources, several major projects are expected to come on-line during the forecast horizon, as listed in the IESO's 18 month forecast. These projects are listed in Table 2 and have been included in the model specification. Four large gas-fired generators are scheduled to be in-service by the first quarter of 2009: the 1005 MW Greenfield Energy Centre, the 860 MW Goreway Station, the 570 MW St. Clair Energy Centre and the 538 MW Portlands Energy Center. In addition to the projects in Table 2, the OPA has contracted with various small renewable energy power producers under the Renewable Energy Standard Offer Program (RESOP). If the projects come into service as planned under their contracts, this program would add a further 524 MW of wind, 54 MW of hydroelectric and biomass, and 264 MW of photovoltaic (solar) capacity during the forecast period.

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2 The IESO 18-month outlook presented two scenarios for the peak demand and energy forecast with respect to the conservation impact. The "Firm Resource" scenario completely discounted conservation measures undertaken, whereas the "Planned Resource" scenario included the full impact of conservation on peak demand and energy consumption forecasts. NCI has assumed that 50% of the impact of conservation measures in the IESO's "Planned Resource" scenario are realized over the forecast horizon.

Table 2: Major Generation Capacity Additions

Term	Project Name	Resource Type	Capacity (MW)	In-service date
RPP Period	Countryside London Cogeneration Facility	Gas Cogen	12	Q4-2009
	Umbata Falls	Water	23	Q4-2008
	OPG Lac Seul	Water	13	Q4-2008
	Kruger Energy Port Alma	Wind	101	Q4-2008
	Greenfield Energy Centre	CCGT	1005	Q4-2008
	Melancthon II	Wind	132	Q4-2008
	Enbridge	Wind	200	Q4-2008
	St. Clair Energy Center	CCGT	570	Q1-2009
	Goreway Station	CCGT	860	Q1-2009
	Portlands Energy Centre Combined Cycle	CCGT	538	Q1-2009
	Beck Unit 7	Water	59	Q1-2009
	Wolfe Island	Wind	198	Q2-2009
	Algoma Energy Cogen	Industrial Gas	63	Q2-2009
	Nuclear Upgrade	Nuclear	27	Q2-2009
	East Windsor Cogeneration Centre	Gas Cogen	84	Q3-2009
	Bruce Unit 2	Nuclear	750	Q4-2009
Other	Lower Wawiatin Conversion	Water	-11	Q1-2010
	Bruce Unit 1	Nuclear	750	Q1-2010

Source: OPA, IESO

3.1.3 Nuclear Capacity

The statistical model finds that the performance of the nuclear generation fleet is an important factor in influencing HOEP, so the HOEP forecast needs a forecasts of nuclear output.

For the Darlington and Pickering plants, the forecast of nuclear capacity factors is taken from information submitted by Ontario Power Generation as part of its application to the Ontario Energy Board for a rate increase. The submission shows OPG's budget and actual nuclear output by month from 2005 through 2009. For Bruce, historical generation patterns were used to estimate monthly capacity factors. All plants show higher capacity factors during summer and winter and lower capacity factors during the shoulder seasons.

3.1.4 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's *Ontario Transmission System* report, 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 this report. The interconnection limits shown in Table 3 reflect the capacity added for this period by the new 1,250 MW interconnection with Quebec. The IESO reported that the line will have 750 MW of import capacity and 1,000 MW of export capacity through the forecast period.[3]

Table 3: Ontario Interconnection Limits

Interconnection	Flows Out of Ontario (MW)	Flows Into Ontario (MW)
Manitoba		
Summer	262	330
Winter	274	342
Minnesota		
Summer	140	90
Winter	140	90
Michigan		
Summer	2,080	1,640
Winter	2,400	1,800
New York		
Summer	1,850	1,650
Winter	2,000	1,710
Quebec		
Summer	1,662	2,288
Winter	1,747	2,383

Source: IESO, *Ontario Transmission System*, September 23, 2008

3.1.5 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

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.[4]

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[3] Independent Electricity System Operator, *18-Month Outlook: An Assessment of the Reliability of the Ontario Electricity System, From October 2008 to March 2010*, Sept. 23, 2008, pg. 30.

[4] NYMEX future prices averaged over 20 day trading period from September 1 - 23, 2008.

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 South-western Ontario. This basis differential is based on Navigant Consulting's North American gas price forecast.

Natural gas price assumptions are presented in Table 4 below. All prices are in Canadian dollars per MMBtu. The forecast average Dawn natural gas price for the twelve months commencing November 2008 is C$9.27 / MMBtu. The forecast average price over the entire 18-month period is C$9.58 / MMBtu. The twelve-month forecast was used to establish the RPP prices in the *RPP Price Report (November 2008 – October 2009)*.

Table 4: Natural Gas Price Forecast

Term	Month	Henry Hub (US $/MMBtu)	Dawn (C$/MMBtu)
RPP Year	Nov-08	$7.98	$8.98
	Dec-08	$8.38	$9.41
	Jan-09	$8.61	$9.72
	Feb-09	$8.64	$9.76
	Mar-09	$8.50	$9.57
	Apr-09	$8.25	$9.29
	May-09	$8.27	$9.29
	Jun-09	$8.37	$9.30
	Jul-09	$8.48	$9.45
	Aug-09	$8.56	$9.50
	Sep-09	$8.59	$9.70
	Oct-09	$8.67	$9.88
Other	Nov-09	$8.98	$10.38
	Dec-09	$9.33	$10.77
	Jan-10	$9.56	$11.03
	Feb-10	$9.53	$11.00
	Mar-10	$9.30	$10.70
	Apr-10	$8.40	$9.63

Source: NYMEX, Navigant Consulting

3.1.6 Coal Prices and Output

Under new carbon dioxide (CO_2) emissions limits being introduced in 2009 in Ontario, the effective cost of coal generation will be less dependent on the price of the fuel and more dependent on OPG's management of its coal resources.

Over the past four years, OPG's coal-fired fleet contributed an average of 27.6 TWh to Ontario's electricity supply. The government has directed OPG to limit CO_2 emissions from its coal-fired electricity generation facilities beginning January 1, 2009. OPG will face a limit of 19.6 million tonnes in 2009 and 15.6 million tonnes in 2010, which means the output of the coal plants will be limited to just under 20 TWh in 2009 and between 15 and 16 TWh in 2010. Although OPG is subject to a revenue cap on 85 percent of the output from these assets until April 30, 2009, OPG still has incentives to maximize the revenue they produce. OPG has stated that its general approach will be to offer the limited output from these assets at higher prices so that it is displaced by other generation in the electricity market.[5] OPG is required to publish its strategy for reducing coal-fired generation by November 30, 2008. At that time, OPG will provide more specifics on how it will manage its coal-fired stations, and how it will modify its offers of coal-fired generation into the Ontario real time electricity market. For price forecast purposes, Navigant Consulting has assumed that OPG will add a charge per tonne of CO_2 emissions to all of its market bid prices, using the same charge for all plants and for all months in 2009, with a higher charge in 2010.

3.1.7 Hydro Resources

Our statistical model for Ontario requires a specification of the monthly average hydroelectric output for the province. In our base case, we assume a normal hydroelectric resource level. Our forecast of hydroelectric generation is based on a statistical analysis of historical monthly generation and its seasonality pattern. It has been a very wet year in 2008, and total hydroelectric generation has been well above normal throughout the year. For the forecast, we have assumed that November and December of 2008 will remain slightly above normal, but that 2009 will return to the average historical pattern.

Review of Forecast Results

Table 5 presents the results of our base case market price forecast based on our statistical model. The 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. [6] 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.

[5] http://www.opg.com/safety/sustainable/emissions/carbon.asp

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

Table 5: HOEP Forecast (CAD $ per MWh)

Term	Quarter	Calendar Period	On-Peak	Off-Peak	Average	Term Average
RPP Year	Q1	Nov 08 - Jan 09	$60.70	$40.04	$49.47	
	Q2	Feb 09 - Apr 09	$60.80	$41.79	$50.49	
	Q3	May 09 - Jul 09	$62.17	$34.32	$47.17	
	Q4	Aug 09 - Oct 09	$68.50	$41.14	$53.54	$50.16
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	Q2	Feb 10 - Apr 10	$59.37	$39.58	$48.62	$50.66

Source: NCI

Notes

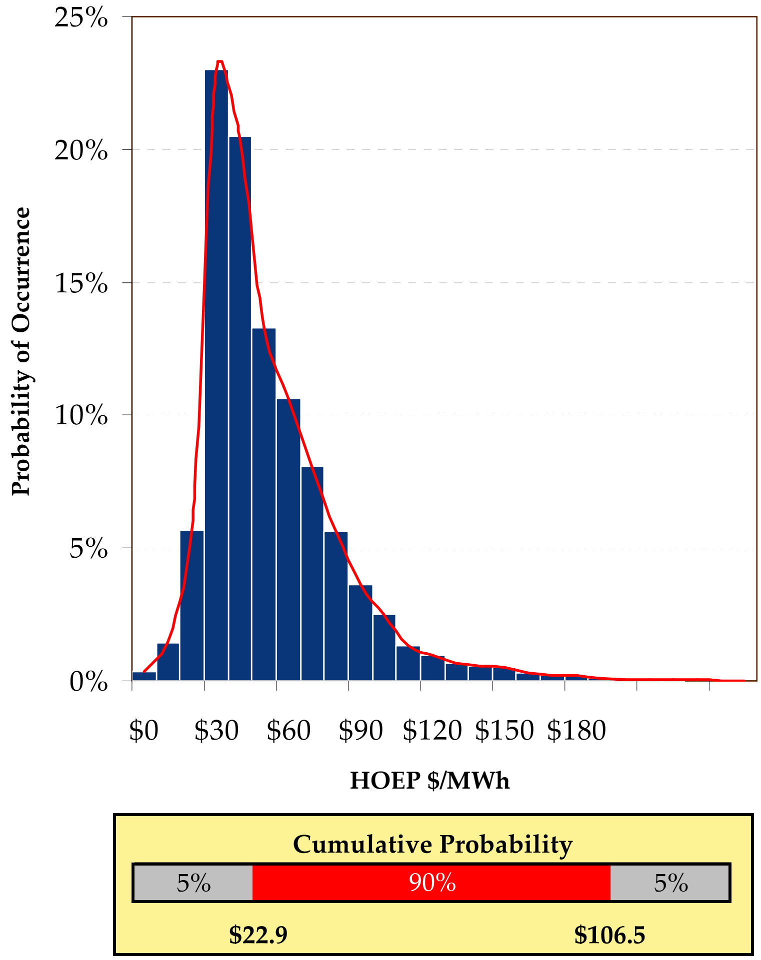
1) The prices reflect an exchange rate of $1.00 CAD to $0.946 USD.

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

This price forecast is based on market fundamentals and reflects the assumptions used for the forecast from the statistical model. To the degree that actual market variables (gas prices, hourly loads and generator availabilities) are different from 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 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 that both are skewed to the right, indicating that the average value is higher than the median or 50% percentile value.

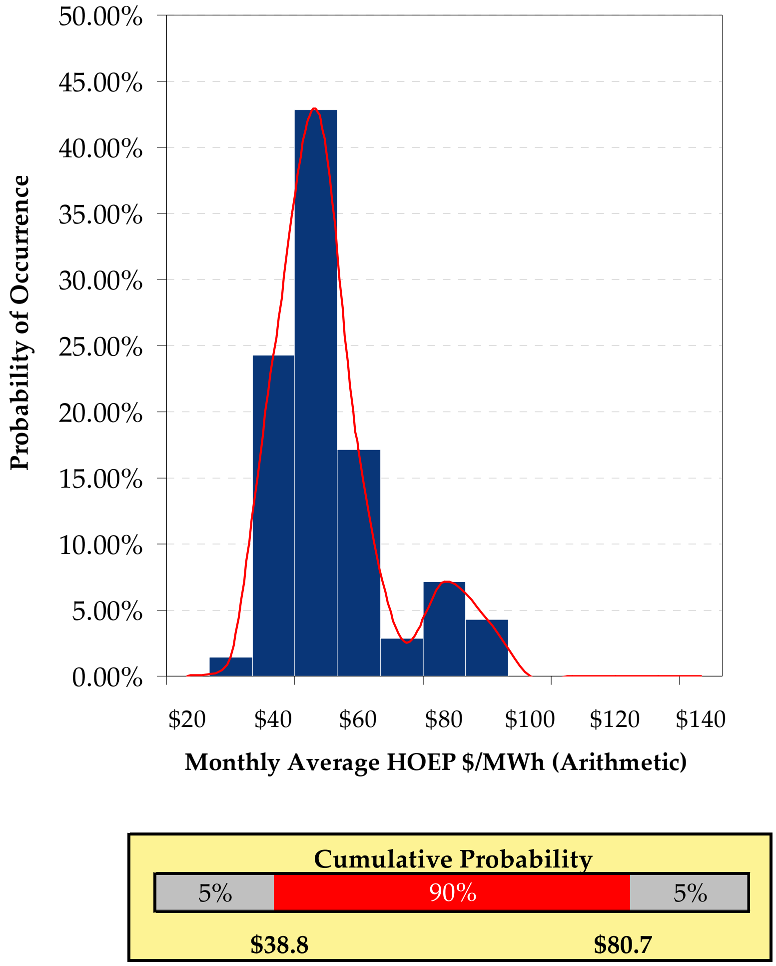
Not surprisingly, the hourly price distribution is significantly more skewed to the right than the monthly price distribution, reflecting the averaging that occurs for the monthly prices. While not as skewed as the distribution of hourly prices, Figure 2 demonstrates that even the distribution of monthly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

Figure 1: Historic Distribution of Hourly HOEP



Source: NCI analysis of IESO data (May 2002 to August 2008)

Figure 2: Historic Distribution of Monthly Average HOEP



Source: NCI analysis of IESO data (May 2002 to August 2008)

4. Assessment of Forecast Risks

As discussed above, the foundation of our HOEP forecast is a statistical model of the Ontario electricity market. This forecast is developed using single point forecasts for each of the determinants of price. There could be 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 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 is assessed below.

4.1 Load Forecast Risk

As discussed, the energy demand forecast used by Navigant Consulting was developed by the IESO. Their 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 450 MW increase in the daily peak demand. The IESO's September 2008 18-Month Outlook forecasts a normal weather pre-conservation summer peak of 24,987 MW and an extreme weather peak of 27,898 MW for the summer of 2009, 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 (November 2008 – October 2009)*. 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.

4.2 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, but 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), the GTAA Cogeneration Facility (117 MW) and the Portlands Energy Centre (opened at 250 MW). There was approximately 1,500 MW of gas-fired generation operating under contract in the summer of 2008 (not including NUGs). This is expected to almost triple by the summer of 2009, to approximately 4,300 MW. 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 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 statistical 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 futures contracts over a 20 trading day period.

Figure 3 illustrates the trend in forward prices for natural gas for May 2009 delivery since May 2002. Navigant Consulting's assumption used in the statistical forecast was based on an average of settlement prices over a 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 November 2008 Futures Prices (US$/MMBtu)

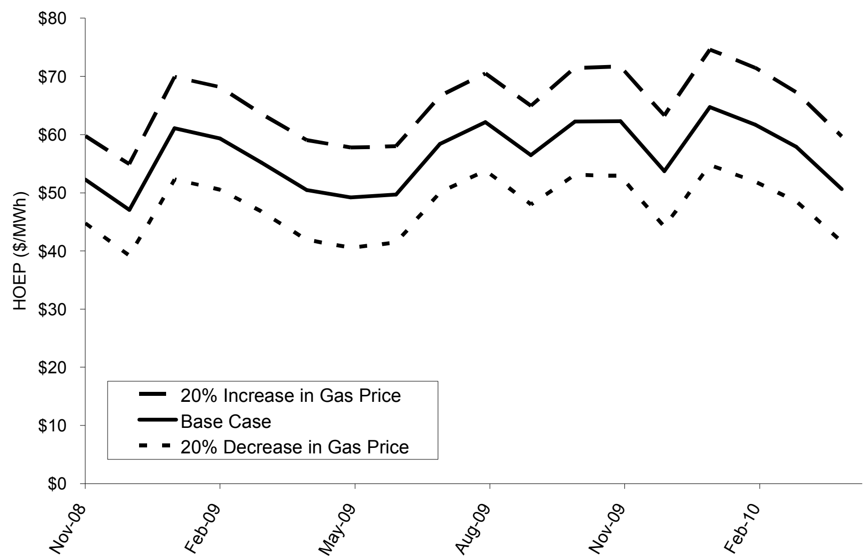
Source: NYMEX

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.

Based on this assessment and the experience of the late summer and fall of 2005 (when both gas and electricity prices were very high), and the winter of 2006/2007 (when prices were low), 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 can result in significant increases in natural gas prices. Conversely, a warm winter or cool summer can result in a softening of near-term natural gas prices.

Navigant Consulting has evaluated the impact of a ± 20% change in Henry Hub natural gas prices on the HOEP. The results of this analysis are shown in Figure 4 which shows the monthly average HOEP for the base case as well as high and low natural gas price sensitivities. This analysis indicated that the HOEP increased by an average of about 16% when natural gas prices were assumed to be 20% higher than forecast and also decreased by an average of 16% when natural gas prices were assumed to be 20% lower than forecast.

Figure 4: Comparison of Monthly Average HOEP with ±20% Change in Henry Hub Gas Price



Source: NCI

4.3 Generator Availability Price Risks

The third major source of electricity price forecast risk pertains to the availability of Ontario generation. 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 6 compares our capacity factor assumptions for Ontario's nuclear fleet with recent experience.

Table 6: Comparison of Historical Nuclear Capacity Factors with Forecast Values

	2004	2005	2006	2007	2008 YTD	RPP Year	18 Months
Actual Capacity Factor	79.9%	83.8%	86.8%	83.2%	82.3%		
Forecast Capacity Factor						83.4%	83.3%

Source: NCI analysis of IESO generator disclosure reports.
Notes: 2008 YTD is January to August 2008; "RPP Year" refers to the period November 2008 through October 2009 inclusive; "18 Months" refers to November 2008 through April 2010, the forecast period for this report. The difference between "RPP Year" and "18 Months" is due to normal seasonal variations in nuclear generation.