NAVIGANT CONSULTING

Ontario Wholesale Electricity Market Price Forecast

For the Period November 1, 2009 through April 30, 2011

Presented to

Ontario Energy Board

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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 discussed 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 09 - Jan 10	$46.43	$29.02	$36.93	
	Q2	Feb 10 - Apr 10	$45.43	$29.53	$36.85	
	Q3	May 10 - Jul 10	$39.19	$20.63	$29.18	
	Q4	Aug 10 - Oct 10	$51.43	$30.07	$39.80	$35.68
Other	Q1	Nov 10 - Jan 11	$43.85	$25.20	$33.67	
	Q2	Feb 11 - Apr 11	$42.04	$24.99	$32.84	$33.26

Source: NCI

Notes

1) The prices reflect an average exchange rate of CAD $1.00 CAD to USD $0.986 between November 2009 and April 2011 ($0.978 between November 2009 and October 2010). The exchange rate forecast is taken from the Bank of Montreal's "Canadian Economic Outlook", issued Sept. 25, 2009.

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, 2009 through April 30, 2011 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) and Feed-In tariff (FIT) program 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 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 third 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. Ontario's fleet of natural-gas fired generators has been growing, and two new plants are expected to come into service during the forecast period. Natural gas is also important in setting the price in neighbouring 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.

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 is set by the Ontario Energy Board. 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 2009 –October 2010)*.

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 are presented below.

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 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 Update: An Assessment of the Reliability and Operability of the Ontario Electricity System From September 2009 to February 2011* (August 25, 2009).

The IESO's *18-Month Outlook Update* 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.

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..

1 The price forecast reflects an average exchange rate of $1.00 CAD to $0.986 USD between November 2009 and April 2011 ($0.978 between November 2009 and October 2010). The exchange rate forecast is taken from the Bank of Montreal's "Canadian Economic Outlook", issued Sept. 25, 2009.

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Table 1: Forecast Monthly Energy Consumption and Peak Demand

Year		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2009	Energy (TWh)											11.9	12.7
	Peak Demand (MW)											21,362	21,919
2010	Energy (TWh)	13.1	11.8	12.4	10.8	10.7	11.2	12.3	12.1	11.0	11.4	11.7	12.6
	Peak Demand (MW)	22,848	22,601	21,500	18,844	18,919	22,555	23,936	23,302	21,940	19,761	21,295	22,255
2011	Energy (TWh)	13.1	11.8	12.4	10.8								
	Peak Demand (MW)	22,761	22,750	21,304	18,833								

Source: IESO, *18-Month Outlook Update: An Assessment of the Reliability and Operability of the Ontario Electricity System from September 2009 to February 2011* (August 25, 2009)

3.2 Supply Assumptions

The existing generation capacity assumptions are generally consistent with the IESO's *18-Month Outlook Update* (August 25, 2009), except that some of the in-service dates have been updated based on information from the Ontario Power Authority. Four coal units are expected to retire during the forecast period. Bruce A Unit 2 is expected to return to service in the second quarter of 2010, according to the IESO. Unit 1 is also being refurbished, and is expected to return to service in the third 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 Outlook Update*. These projects are listed in Table 2 and have been included in the model specification. Bruce Unit 2 is expected to return to service in the third quarter of 2009, adding 750 MW of capacity to Ontario's electricity system. Two large gas-fired generators are scheduled to come into service in 2010: Thorold Cogen (236 MW) late in the second quarter and Halton Hills CCGT in the third quarter.

Table 2: Major Generation Capacity Additions

Term	Project Name	Resource Type	Capacity (MW)	In-service date
RPP Period	East Windsor Cogeneration Centre	Gas Cogen	84	Q3-2009
	Fort Frances Conversion to Biomass	Biomass	-58	Q4-2009
	Nuclear Upgrade	Nuclear	27	Q1-2010
	Lower Wawiatin Conversion	Water	-11	Q1-2010
	Thorold Cogen	Gas Cogen	236	Q2-2010
	Healey Falls	Water	16	Q2-2010
	Bruce Unit 2	Nuclear	750	Q3-2010
	Raleigh Wind Energy Centre	Wind	78	Q3-2010
	Halton Hills Generating Station	Industrial Gas	632	Q3-2010
	Bruce Unit 1	Nuclear	750	Q4-2010
	Island Falls	Water	16	Q4-2010
	Byran Wind Project	Wind	65	Q4-2010
	Sandy Falls Conversion	Water	5	Q4-2010
	Lower Sturgeon Conversion	Water	14	Q4-2010
	Lower Wawiatin Conversion	Water	15	Q4-2010
	Hound Chute	Water	10	Q4-2010

Source: IESO, *18-Month Outlook Update: An Assessment of the Reliability and Operability of the Ontario Electricity System September 2009 to February 2011* (August 25, 2009)

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). As of the last status report, dated February 2009, 1,412 MW had been contracted, of which 106 MW was in commercial operation. In March 2009, the Ontario government announced the Feed-In Tariff program (FIT), which offers higher rates and replaces RESOP as a way to contract with renewable energy supply contracts. A few RESOP projects that had not yet reached commercial operation as of March 2009 may have proceeded under RESOP, but it is expected that most projects will either switch to the FIT program, or be cancelled while their proponents concentrate on other projects under the FIT program. It is therefore assumed that 110 MW of renewable capacity will be contracted under RESOP, including 70 MW of wind, 2 MW of solar PV, 12 MW of water power, and 26 MW of bioenergy.

The FIT program has now been launched but it will be several months before any projects under this program reach commercial operation. It is assumed that approximately 250 MW of renewable capacity will come into service during the forecast period.

3.3 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. Historical generation patterns were used to estimate monthly capacity factors for each plant. Average annual capacity factors range from 72% for Pickering to 90% for Darlington, but all plants show higher capacity factors during summer and winter and lower capacity factors during the shoulder seasons. Capacity factors are multiplied by the available capacity (taking into account capacity additions such as the return to service of Bruce Units 1 and 2) and the number of hours in each month to estimate monthly nuclear generation.

Table 3: Historical and Forecast Nuclear Capacity Factors

	2004	2005	2006	2007	2008	2009	2010	2011
Average monthly MW	8,633	8,946	9,584	9,166	9,540	9,254	9,660	10,587
Average monthly capacity	10,863	11,035	11,378	11,378	11,378	10,738	11,692	12,878
Annual capacity factor	79.5%	81.1%	84.2%	80.6%	83.8%	86.2%	82.6%	82.2%

Source: NCI analysis of IESO generator disclosure reports.

3.4 Transmission Capabilities and Constraints

Given that the HOEP is based on a uniform price which does not reflect transmission congestion within Ontario, internal Ontario transmission constraints are not tracked in the forecast model. The transfer capabilities of transmission interconnections with adjacent markets are shown in the IESO's *Ontario Transmission System* (August 25, 2009) report, differentiated by season and direction of flow. Table 4 shows the ratings of Ontario's interconnections with adjacent markets based on the information presented in this report. The capacities for flows between Ontario and Quebec are based on the current status of the HVDC link, with only one converter in service. When the second converter begins operation, expected in Fall 2009, transfer capabilities will increase by up to 625 MW. The market forecast has not been adjusted to reflect this new transmission capacity, as the impact that it will have on prices has yet to be determined. Some narrowing of the difference between on-peak and off-peak prices can be expected (as Quebec is likely to buy more off-peak power from, and sell more on-peak power to, Ontario), but it is not clear whether the net impact will be an increase or a decrease in the average price,

Table 4: 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	1,970	1,680
Winter	2,260	1,960
New York		
Summer	2,060	1,620
Winter	1,900	1,650
Quebec		
Summer	1,287	2,163
Winter	1,372	2,258

Source: IESO, *Ontario Transmission System*, December 22, 2008

3.5 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 a three week period 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.

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 5 below. All prices are in Canadian dollars per MMBtu. The forecast average Dawn natural gas price for the twelve months commencing November 2009 is C$6.11/MMBtu. The forecast average price over the entire 18-month period is C$6.45/MMBtu. The twelve-month forecast was used to establish the RPP prices in the *RPP Price Report (November 2009 – October 2010)*.

Table 5: Natural Gas Price Forecast

Term	Month	Henry Hub (US $/MMBtu)	Dawn (C$/MMBtu)
RPP Year	Nov-09	$4.65	$5.33
	Dec-09	$5.37	$6.08
	Jan-10	$5.64	$6.24
	Feb-10	$5.68	$6.28
	Mar-10	$5.65	$6.28
	Apr-10	$5.63	$6.09
	May-10	$5.67	$6.08
	Jun-10	$5.75	$6.12
	Jul-10	$5.85	$6.06
	Aug-10	$5.94	$6.14
	Sep-10	$6.01	$6.22
	Oct-10	$6.17	$6.40
Other	Nov-10	$6.55	$6.87
	Dec-10	$6.91	$7.20
	Jan-11	$7.14	$7.43
	Feb-11	$7.13	$7.43
	Mar-11	$6.94	$7.24
	Apr-11	$6.41	$6.65

Source: NYMEX, Navigant Consulting

3.6 Coal Prices and Output

Under new carbon dioxide (CO_2) emissions limits being introduced in 2009 in Ontario, the impact of coal generation on market prices 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 (2005 – 2008), 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 faces a limit of 19.6 million tonnes in 2009, falling to 15.6 million tonnes in 2010 and 11.5 million tonnes from 2012 on. The coal plants emit approximately one tonne of CO_2 for each MWh of electricity produced, so this means the output of the coal plants will be limited to just under 20 TWh in 2009,between 15 and 16 TWh in 2010, and between 11 and 12 TWh in 2011.

OPG has published its strategy for meeting the emission limits in 2009[2]; it consists of a combination of making only some of its coal plants available at certain times, and adding a uniform emission adder to its offers into the wholesale market. However, the $7.50/tonne adder was reduced to zero in March 2009, presumably because it was not expected to be needed in order to meet the emission limit. Coal plant generation from January through August 2009 was approximately 60% below historical levels. This was in part due to implementation of OPG's emission strategy, but market conditions played a more important role. Nuclear and hydro baseload generation was at or above normal levels, while demand was significantly lower. Since coal provides much of the "swing" generation that makes up the difference between must-run generation and demand, coal output would have been significantly below historical levels even without any special efforts to reduce emissions.

The Ontario government has announced that four of the units at the Lambton and Nanticoke coal plants, representing about one-third of the province's coal-fired generating capacity, will be closed in October 2009. Navigant Consulting estimates that with no special efforts other than the closing of these units (i.e., no adder or withholding), CO_2 emissions from the coal facilities would amount to approximately 12 million tonnes in 2009 (39% below the limit of 19.6 million tonnes), 15.6 million tonnes in 2010 (very close to the limit of 15.6 million tonnes), and 11.1 million tonnes in 2011 (just under the limit of 11.5 million tonnes). This implies that OPG will not need to put an adder on its market bids or withhold capacity during the forecast period. The only impact that the emission limits are expected to have on electricity prices is therefore due to the closure of some of the coal units, beginning in October 2010 on, which will reduce supply and therefore push up prices.

3.7 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. Generation has been slightly above normal so far this year. For the forecast, we have assumed a return to normal output, in line with historical generation levels.

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2 Ontario Power Generation, "OPG's Strategy to Meet on a Forecast Basis the 2009 CO_2 Emission Target", available at http://www.opg.com/safety/sustainable/emissions/OPG%20Strategy%20to%20Meet%202009%20CO2%20Emission%20Targets%20Jan%2022.pdf.

4. Review of Forecast Results

Table 6 presents the results of our base case market price forecast based on our statistical model. The prices presented are simple (i.e., not load-weighted) averages.

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.[3] Nuclear and coal maintenance outages tend to be scheduled in the shoulder seasons, reducing 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	Nov 09 - Jan 10	$46.43	$29.02	$36.93	
	Q2	Feb 10 - Apr 10	$45.43	$29.53	$36.85	
	Q3	May 10 - Jul 10	$39.19	$20.63	$29.18	
	Q4	Aug 10 - Oct 10	$51.43	$30.07	$39.80	$35.68
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Source: NCI

Notes

1) The prices reflect an average exchange rate of $1.00 CAD to $0.986 USD between November 2009 and April 2011 ($0.978 between November 2009 and October 2010). The exchange rate forecast is taken from the Bank of Montreal's "Canadian Economic Outlook", issued Sept. 25, 2009.

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.

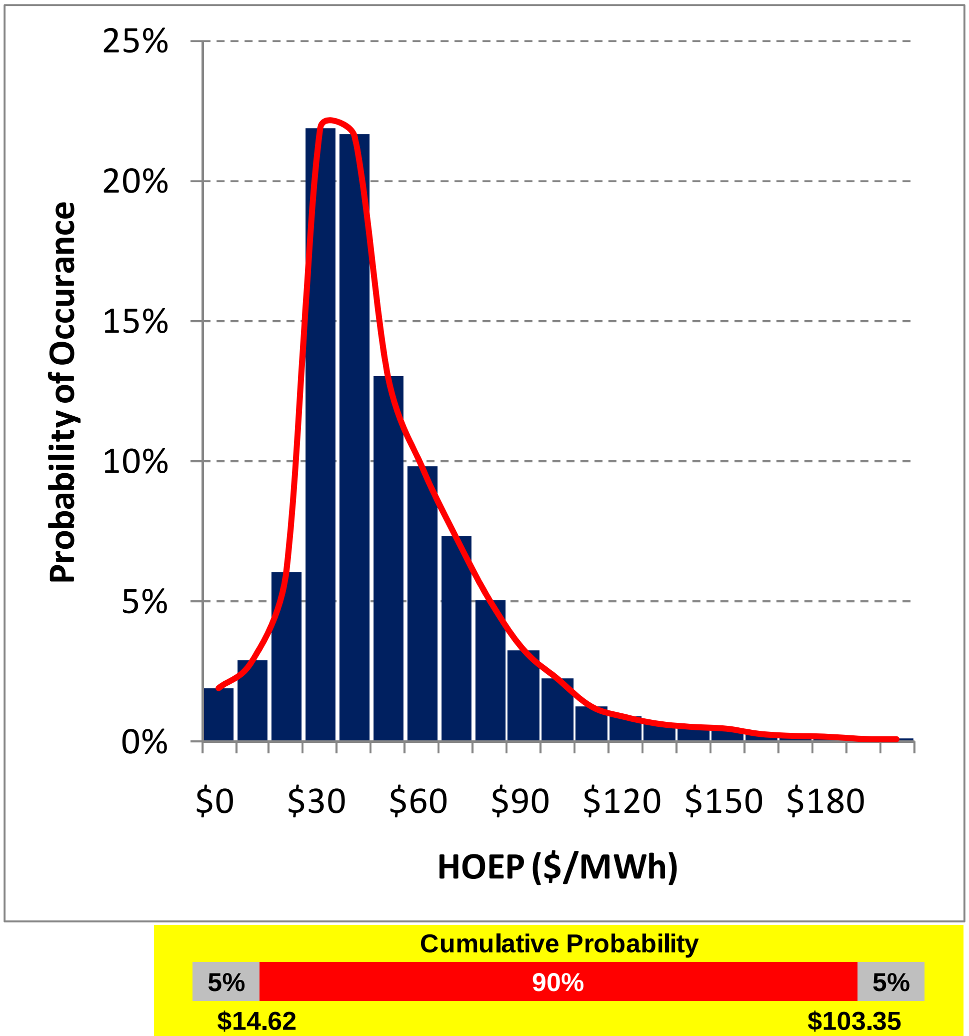
This price forecast is based on market fundamentals and reflects the assumptions used for the forecast from the statistical model. To the degree that actual market variables (gas prices, hourly loads and generator availabilities) are different from our forecast assumptions, market prices are likely to 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, and 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

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

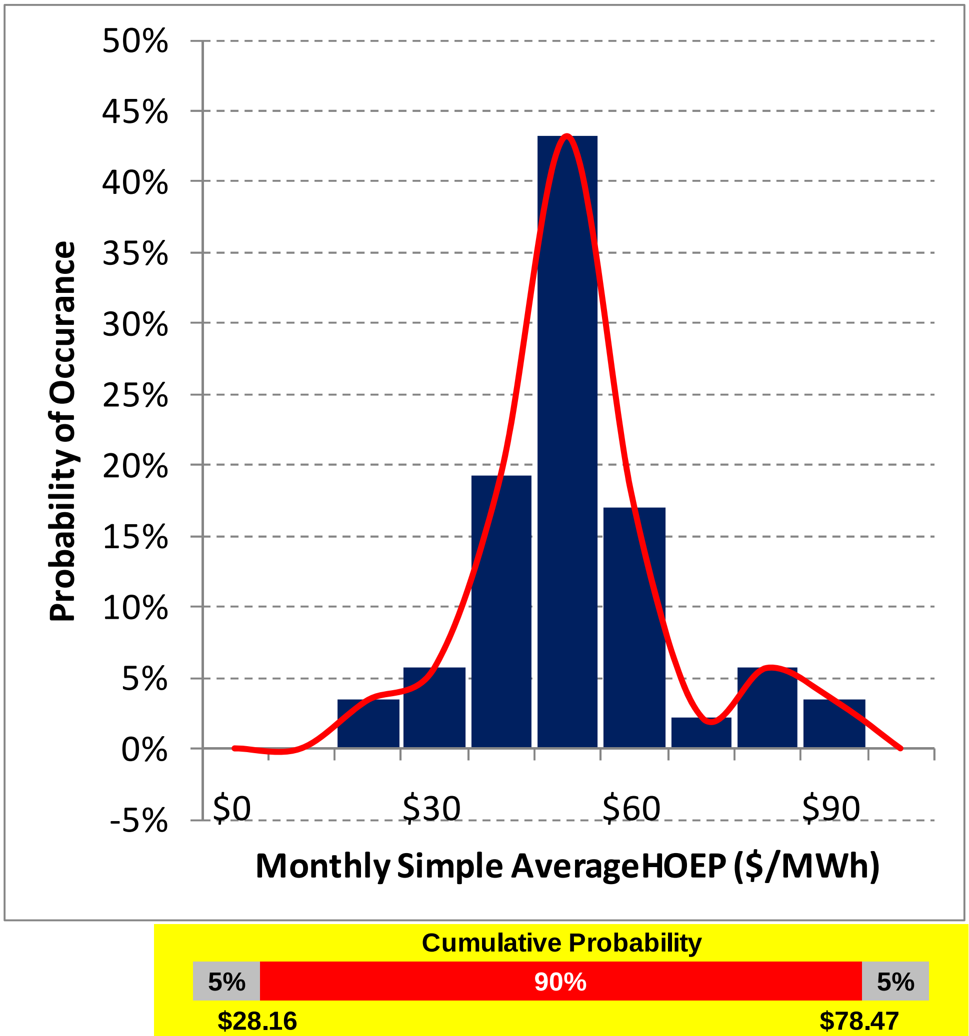
not as skewed as the distribution of hourly prices, Figure 2 demonstrates that even the distribution of monthly prices is skewed to the right.

Figure 1: Historic Distribution of Hourly HOEP



Source: NCI analysis of IESO data (May 2002 to August 2009)

Figure 2: Historic Distribution of Monthly Average HOEP



Source: NCI analysis of IESO data (May 2002 to August 2009)

5. 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 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 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 four major risks that an electricity price forecast will not be realized. These stem from differences between forecast and actual: (1) load; (2) fuel prices; (3) generator availabilities; and (4) the impact of the coal emission limits. Each of these forecast risks is assessed below.

5.1 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, other random factors, such as economic activity or consumer behaviour, will cause actual loads to vary from the forecast. 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 August 25, 2009 *18-Month Outlook Update* forecasts a normal weather summer peak of 23,936 MW and an extreme weather peak of 26,513 MW for the summer of 2010, 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 2009 – October 2010)*. 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

In general, the fuel price with the greatest impact on electricity market prices is the gas price. Currently Ontario has a moderate 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 Greenfield Energy Centre (1,005 MW), Goreway Station (839 MW), St. Clair Energy Centre

(577 MW), , Brighton Beach Power Station (550 MW), Portlands Energy Centre (550 MW), the Sarnia Regional Cogeneration Plant (505 MW) and the GTAA Cogeneration Plant (90 MW). There was approximately 4,200 MW of gas-fired generation operating under contract in August 2009 (not including Lennox and the NUGs). This is expected to increase by 950 MW, to approximately 5,150 MW, by the end of the third quarter of 2010. 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 gas prices used by Navigant Consulting for this forecast were based on 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.

The most obvious risk associated with natural gas prices is the inherent price volatility of the commodity itself. Figure 3 illustrates the trend in forward prices for natural gas for November 2009 delivery since May 2002. 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 three week 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 2009 Futures Prices (US$/MMBtu)

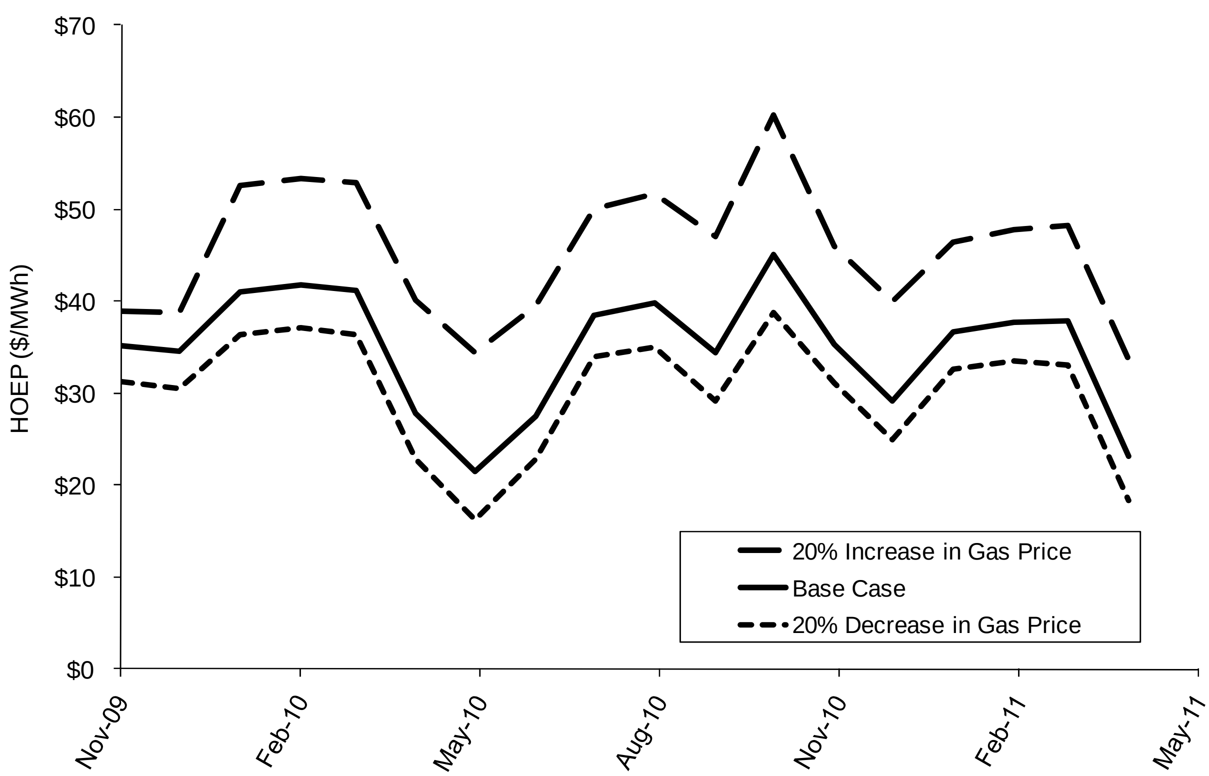
Source: NYMEX

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 indicates that the forecast of HOEP increased by an average of 32% when natural gas prices were assumed to be 20% higher than forecast, and decreased by an average of 14% when natural gas prices were assumed to be 20% lower than forecast. HOEP has become more sensitive to increases in gas prices because the amount of coal generation available is limited by the CO_2 emission limits.

Figure 4: 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. 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. As Table 3 in Section 3.3 above shows, our capacity factor assumptions for Ontario's nuclear fleet are consistent with recent experience.

5.4 Impact of Coal Emission Limits

Navigant Consulting estimates that in January and February 2009, OPG's efforts to limit CO_2 emissions by its coal plants increased market prices by approximately $14/MWh. Navigant Consulting estimates that the coal plants will undershoot the emissions target of 19.6 million tonnes for 2009 by approximately 40%, and will come in at or just under the targets for 2010 and 2011 (15.6 and 11.5 million tonnes respectively) without any adders, withholding, or other OPG efforts to limit generation. The base case price forecast takes into account the planned closure of four large coal units in October 2010, which will limit supply and therefore increase prices, but does not assume that the CO_2 emission limits will have any additional impact on electricity prices over the forecast period. The plant closures are estimated to increase electricity prices by an average of $5/MWh between November 2009 and October 2010, and by an average of $8 over the entire forecast period (November 2009 to April 2011). They will have very little impact during the RPP period for which this forecast was prepared, as that period ends in October 2010, around the same time that the units will be closed.

In the past, coal generation has served to moderate price fluctuations, decreasing when other factors were pushing electricity prices down, and increasing when other factors were pushing electricity prices up. The first effect still occurs: now that low demand and low gas prices are pushing electricity prices down to record low levels, coal generation is also very low. However, the second effect is now limited by the CO_2 emission limits. If other factors (high gas prices, high demand, low hydro generation, nuclear outages, etc.) push electricity prices above Navigant Consulting's forecast, the increase is likely to be much greater than it would have been without the CO_2 emission limits.