NAVIGANT
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Ontario Wholesale Electricity Market Price Forecast

For the Period
May 1, 2011 through October 31, 2012

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 Ltd. (Navigant) 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 used a statistical model of the Ontario electricity market to develop our hourly Ontario electricity price (HOEP) forecast. Navigant'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	May 11 - Jul 11	$43.92	$27.13	$34.89	
	Q2	Aug 11 - Oct 11	$48.39	$32.36	$39.64	
	Q3	Nov 11 - Jan 12	$55.66	$38.70	$46.43	
	Q4	Feb 12 - Apr 12	$47.06	$33.31	$39.63	$40.15
Other	Q1	May 12 - Jul 12	$43.91	$26.42	$34.51	
	Q2	Aug 12 - Oct 12	$46.40	$29.85	$37.37	$35.94

Source: Navigant Consulting

Notes

1) The price forecast reflects an average exchange rate of $1.032 CAD between May 2011 and October 2012 ($1.039 CAD between May 2011 and April 2012). The exchange rate forecast is taken from the Bank of Montreal's "Canadian Economic Outlook", issued April 1, 2011.

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 Ltd. (Navigant) 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, 2011 through October 31, 2012 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", Combined Heat and Power 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 used our statistical price forecasting model to develop the HOEP forecast. Navigant'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 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 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 increased. The recent retirement of four coal units, representing almost 2000 MW of generation, will further increase the importance of natural gas generation in Ontario. 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 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 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 are presented in the *RPP Price Report (May 2011 – April 2012)*.

3. Short-Term Forecast Assumptions

As discussed above, Navigant has used 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 March 2011 to August 2012* (February 25, 2011).

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.

Table 1: Forecast Monthly Energy Consumption and Peak Demand

		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2011	Energy (TWh)					10.9	11.5	12.4	12.5	11.1	11.4	11.8	12.9
	Peak Demand (MW)					18,515	22,236	23,561	22,893	20,426	18,944	20,457	21,570
2012	Energy (TWh)	13.4	12.3	12.4	11.0	11.0	11.6	12.5	12.6	11.2	11.5	11.9	12.9
	Peak Demand (MW)	22,628	21,645	20,871	19,387	18,900	22,291	23,449	23,153	19,916	19,385		

Source: IESO, *18-Month Outlook Update: An Assessment of the Reliability and Operability of the Ontario Electricity System From March 2011 to August 2012* (February 25, 2011)

[1]1) The price forecast reflects an average exchange rate of $1.032 CAD between May 2011 and October 2012 ($1.039 CAD between May 2011 and April 2012). The exchange rate forecast is taken from the Bank of Montreal's "Canadian Economic Outlook", issued April 1, 2011 .

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3.2 Supply Assumptions

The existing generation capacity assumptions are consistent with the IESO's *18-Month Outlook Update* (February 25, 2011). Two Bruce nuclear units are expected to return to service in Q1 and Q3 of 2012 respectively, and 800 MW of new renewable generation is anticipated. Coal Units 3 and 4 from Nanticoke are expected to be retired from service in 2011.

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. Projects which have now come into service since the last update include Hound Shute (10 MW), Lower Sturgeon (14 MW), Kruger Energy Chatham Wind Project (101 MW) and the Gosfield Wind Project (50 MW).

Table 2: Major Generation Capacity Additions

Term	Project Name	Resource Type	Capacity (MW)	In-service date
RPP Period	Raleigh Wind Energy Centre	Wind	78	2011-Q1
	Talbot Windfarm	Wind	99	2011-Q1
	Leamington Pollution Control Plant	Oil	2	2011-Q2
	Greenwich Wind Farm	Wind	99	2011-Q3
	Becker Cogeneration	Biomass	15	2011-Q3
	Grid-connected FIT Projects	Wind	50	2011-Q3
	Grid-connected FIT Projects	Wind	10	2011-Q3
	Grid-connected FIT Projects	Wind	83	2011-Q3
	Grid-connected FIT Projects	Wind	83	2011-Q3
	Grid-connected FIT Projects	Wind	49	2011-Q3
	Nanticoke Capacity Adjustment	Coal	-980	2011-Q4
	Grid-connected FIT Projects	Wind	69	2011-Q4
	Bruce Unit 2	Uranium	750	2011-Q3
	Grid-connected FIT Projects	Wind	125	2012-Q1
	Bow Lake Phase 1 (FIT)	Wind	20	2012-Q2
	Bruce Unit 1	Uranium	750	2011-Q4

Source: IESO, *18-Month Outlook Update: An Assessment of the Reliability and Operability of the Ontario Electricity System From March 2011 to August 2012* (February 25, 2011).

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). In March 2009 the Ontario government announced the Feed-In Tariff program (FIT), which offers higher rates and replaces RESOP and request for proposal processes as the primary method to procure renewable energy supply contracts. In the interim, many RESOP contract holders have opted to apply for the FIT program; however as of the last status report published by the OPA, updated for the fourth quarter of 2010, 915 MW remain under contract, of which 424 MW were in commercial operation. Of the 491 MW under development, 131.5 MW are wind projects and 327.6 MW are solar PV projects. A significant proportion of the solar PV projects are assumed to have signed a RESOP extension, allowing them to reach commercial operation one year later than their original expected commercial operation date.

The OPA has received over 24,000 applications under the microFIT program and over 4,100 applications under the FIT program representing approximately 220 MW and 16,200 MW, respectively. At the end of the fourth quarter, it had issued over 18,000 conditional offers under the microFIT program for a total of 167 MW. The number of FIT contracts issued to date is 1,208 with the capacity of 2,590 MW. About 59% of the total FIT MWs approved to date are for wind projects and 32% are for solar PV projects.

Renewable generation under contract with the OPA supplied generation equivalent to approximately 5% of Ontario demand in 2010. This is estimated to increase to 6% by 2011 and 8% in 2012. The effect of this increase in supply is to decrease Ontario wholesale electricity prices.

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 forecast 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 91% for Darlington, but all plants show higher capacity factors during summer and winter and lower capacity factors during the shoulder seasons (spring and fall). 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

	2007	2008	2009	2010	2011	RPP Year	18 Months
Average monthly MW	9,166	9,540	9,361	9,461	9,934	9,995	10,259
Average monthly capacity	11,378	11,378	11,378	11,378	11,378	11,503	11,795
Annual capacity factor	80.6%	83.8%	82.3%	83.1%	87.3%	86.9%	87.0%

Source: Navigant Consulting 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* (December 3, 2010) 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 flow capacities for Quebec include the full 1,250MW capacity of the new Hawthorne-Outaouais HVDC line. 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	1,840	1,580
Winter	1,980	1,860
New York		
Summer	1,960	1,520
Winter	2,280	1,770
Quebec		
Summer	1,912	2,788
Winter	1,997	2,883

Source: IESO, *Ontario Transmission System*, December 3, 2010

3.5 Fuel Prices

Given the uncertainty associated with fuel price forecasts, Navigant 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 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's North American gas price forecast.

Natural gas price assumptions are presented in Table 5 below. All prices are in dollars per MMBtu – US dollars for Henry Hub, Canadian dollars for Dawn. The forecast average Dawn natural gas price for the twelve months commencing May 2011 is C$4.76/MMBtu. The forecast average price over the entire 18-month period is C$4.86/MMBtu. The twelve-month forecast was used to establish the RPP prices in the *RPP Price Report (May 2011 – April 2012)*.

Table 5: Natural Gas Price Forecast

Term	Month	Henry Hub (US $/MMBtu)	Dawn (C$/MMBtu)
RPP Year	May-11	$4.16	$4.43
	Jun-11	$4.23	$4.48
	Jul-11	$4.30	$4.45
	Aug-11	$4.34	$4.47
	Sep-11	$4.36	$4.51
	Oct-11	$4.41	$4.54
	Nov-11	$4.59	$4.87
	Dec-11	$4.84	$5.02
	Jan-12	$4.97	$5.18
	Feb-12	$4.95	$5.15
	Mar-12	$4.90	$5.06
	Apr-12	$4.76	$4.99
Other	May-12	$4.78	$4.97
	Jun-12	$4.82	$4.97
	Jul-12	$4.86	$5.05
	Aug-12	$4.89	$5.06
	Sep-12	$4.90	$5.08
	Oct-12	$4.94	$5.18

Source: NYMEX, Navigant Consulting

3.6 Coal Prices and Output

Under carbon dioxide (CO_2) emissions limits 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.

Between 2005 and 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 was limited to 15.6 million tonnes in 2010 and faces a limit of 11.5 million tonnes from 2011 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 approximately 16 TWh in 2010, and 12 TWh in 2011.

OPG has published its strategy for meeting the emission limits in 2011.[2] It has several ways in which it can limit emissions, including planned outages, offering less than its full capacity into the market, or adding a uniform emission adder to its offers into the wholesale market. OPG does not expect to use any emission reduction strategies in 2011. Coal generation is expected to

[2] Ontario Power Generation, "OPG's Strategy to Meet 2011 CO_2 Emission Target", available at http://www.opg.com/safety/sustainable/emissions/OPG%20Strategy%20to%20Meet%202011%20CO2%20Emission%20Target.pdf

be much lower in 2011 than it was in 2004-2010, primarily because four of the units at the Lambton and Nanticoke coal plants, representing about one-third of the province's coal-fired generating capacity, were closed in 2010, and another two units at Nanticoke are expected to be closed in late 2011, significantly reducing output and emissions. In addition, the downturn in North American economy and the associated weak system demand will reduce output and emissions since coal provides much of the "swing" generation that makes up the difference between must-run generation and demand Navigant 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 will amount to approximately 8.9 million tonnes in 2011 and 7.9 million tonnes in 2012 (well below 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 2011 or 2012. Given that no emission reduction measures and subsequent supply restrictions are anticipated, the influence on prices is expected to be neutral. However, the closure of the six coal units will increase prices.

3.7 Hydro Resources

Navigant's 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 below over the last six months of (September 2010 – February 2011). For the forecast, we have assumed a normal output over the forecast period.

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	May 11 - Jul 11	$43.92	$27.13	$34.89	
	Q2	Aug 11 - Oct 11	$48.39	$32.36	$39.64	
	Q3	Nov 11 - Jan 12	$55.66	$38.70	$46.43	
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	Q2	Aug 12 - Oct 12	$46.40	$29.85	$37.37	$35.94

Source: Navigant Consulting
Notes:
1) The price forecast reflects an average exchange rate of $1.032 CAD between May 2011 and October 2012 ($1.039 CAD between May 2011 and April 2012). The exchange rate forecast is taken from the Bank of Montreal's "Canadian Economic Outlook", issued April 1, 2011.

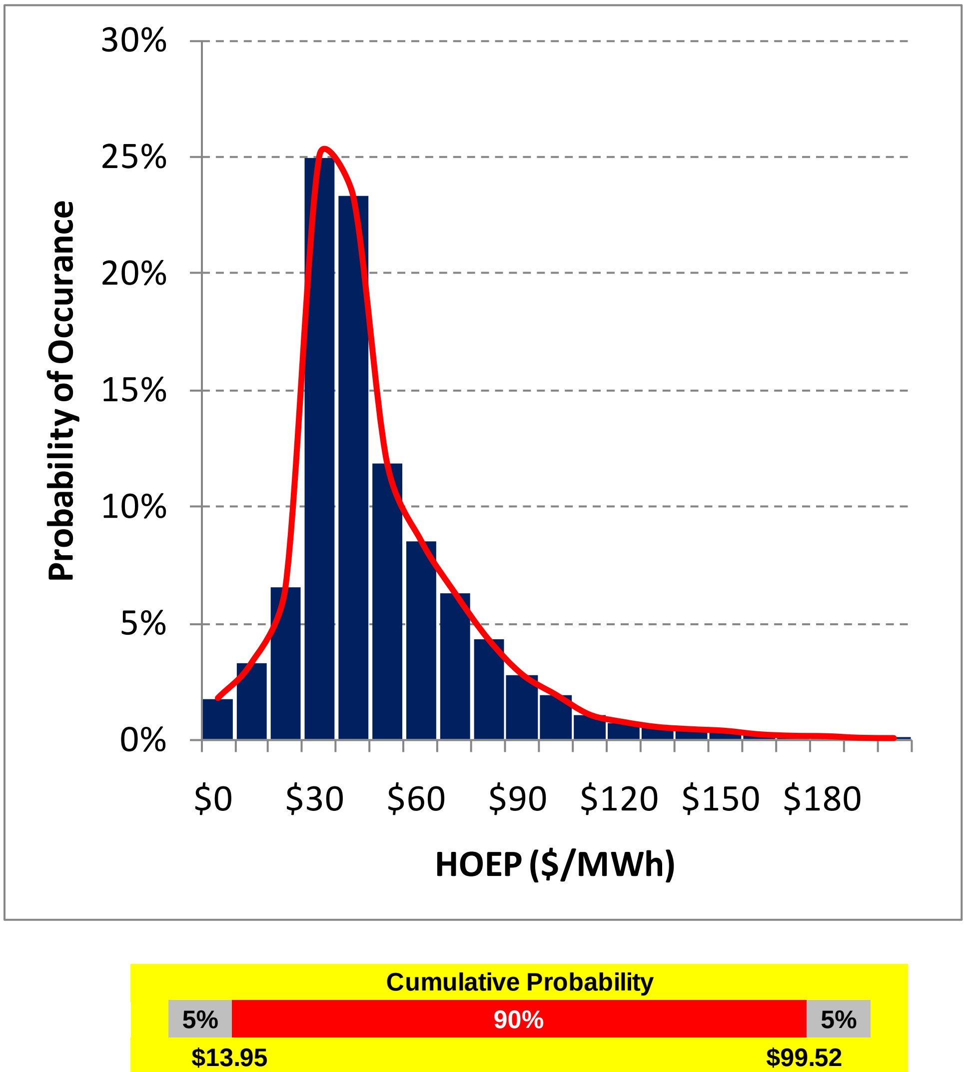
2) On-peak hours include the hours ending at 8 a.m. through 11 p.m. Eastern Time (EST) on working weekdays and off-peak hours include all other hours.

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.

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

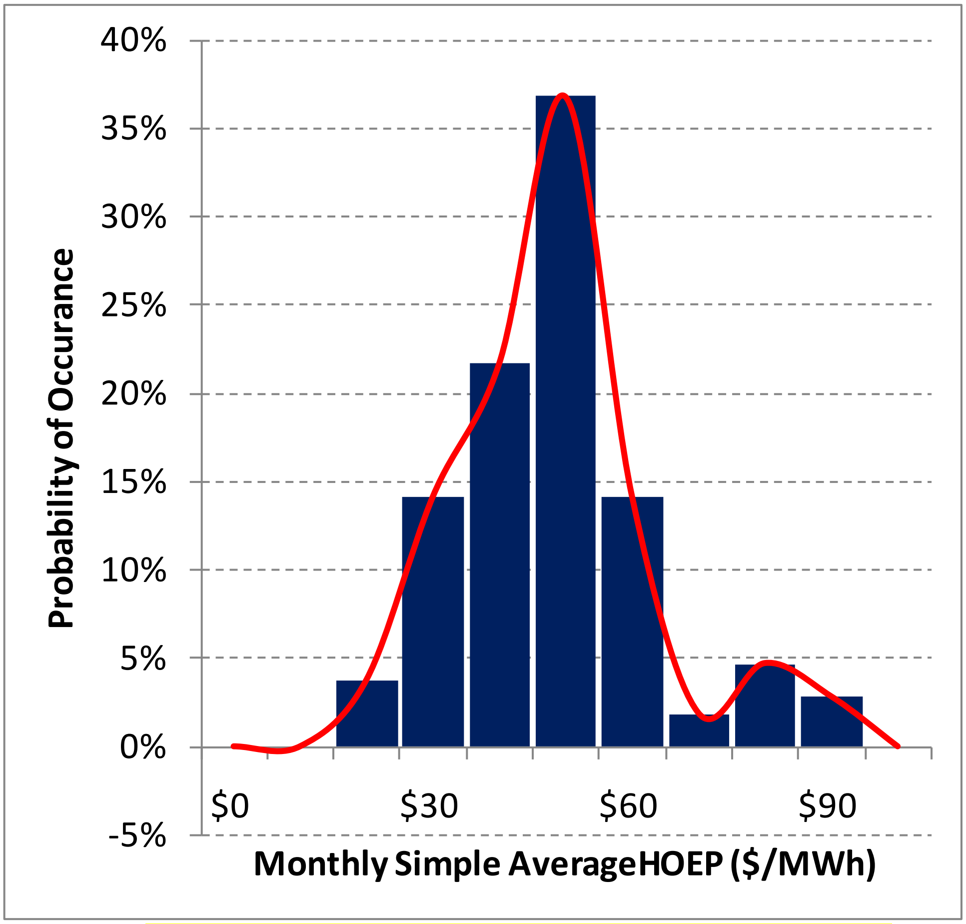
Not surprisingly, the hourly price distribution is significantly more skewed to the right than the monthly price distribution, reflecting the averaging that occurs for the monthly prices. While not as skewed as the distribution of hourly prices, Figure 2 demonstrates that even the distribution of monthly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

Figure 1: Historic Distribution of Hourly HOEP



Source: Navigant Consulting analysis of IESO data (May 2002 to February 2011)

Figure 2: Historic Distribution of Monthly Average HOEP



Cumulative Probability		
5%	90%	5%
$26.85		$76.02

Source: Navigant Consulting analysis of IESO data (May 2002 to February 2011)

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 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 believes that there are four major risks that a specific 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 are assessed below.

5.1 Load Forecast Risk

As discussed, the energy demand forecast used by Navigant 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, actual energy consumption would be expected to vary from forecast consumption. In addition, other factors, such as economic activity or consumer behaviour, will cause actual loads to vary from the forecast. For our short-term forecast, Navigant believes that the greatest source of load forecast risk is weather. The IESO's February 25, 2011 *18-Month Outlook Update* forecasts a normal weather summer peak of 23,561 MW and an extreme weather peak of 25,941 MW for the summer of 2011, 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 2011 – April 2011)*. Analysis of historical price and demand levels clearly demonstrates that load variability is a major contributor to spot market price volatility. Therefore, Navigant believes that this risk has been considered in our price forecasting approach.

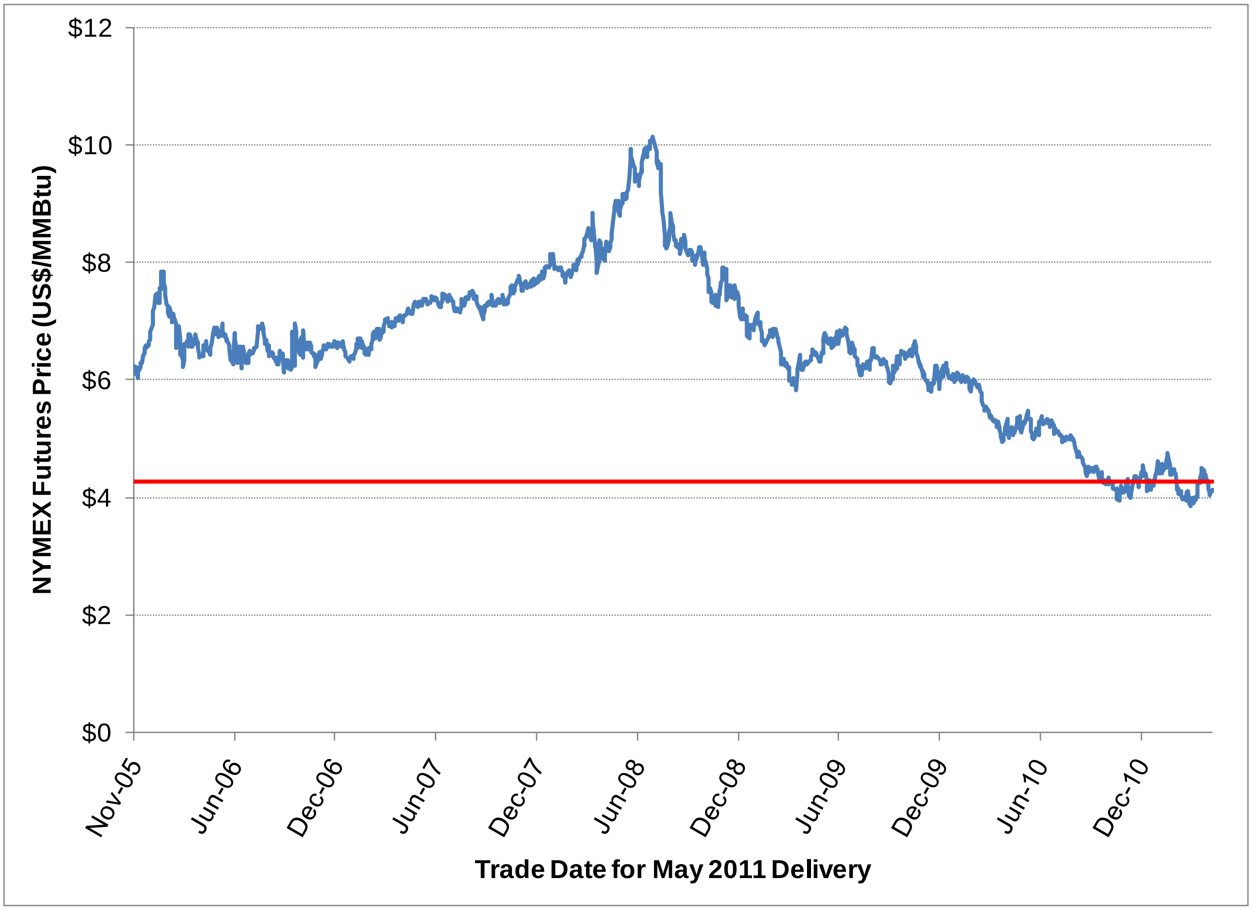
5.2 Fuel Price Forecast Risk

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. However, 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), Halton Hills Generating Station (632 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), Thorold Cogeneration Plant (287 MW) and the GTAA Cogeneration Plant (90 MW). There was approximately 4,500 MW of gas-fired generation operating under contract in August 2009 (not including Lennox and the NUGs). This increased to approximately 5,180 MW with the addition of Halton Hills in the fourth quarter of 2010. No additional gas capacity is expected to come into service over the forecast period. 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 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 2010 delivery since November 2004. 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, Navigant 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 May 2011 Futures Prices (US$/MMBtu)



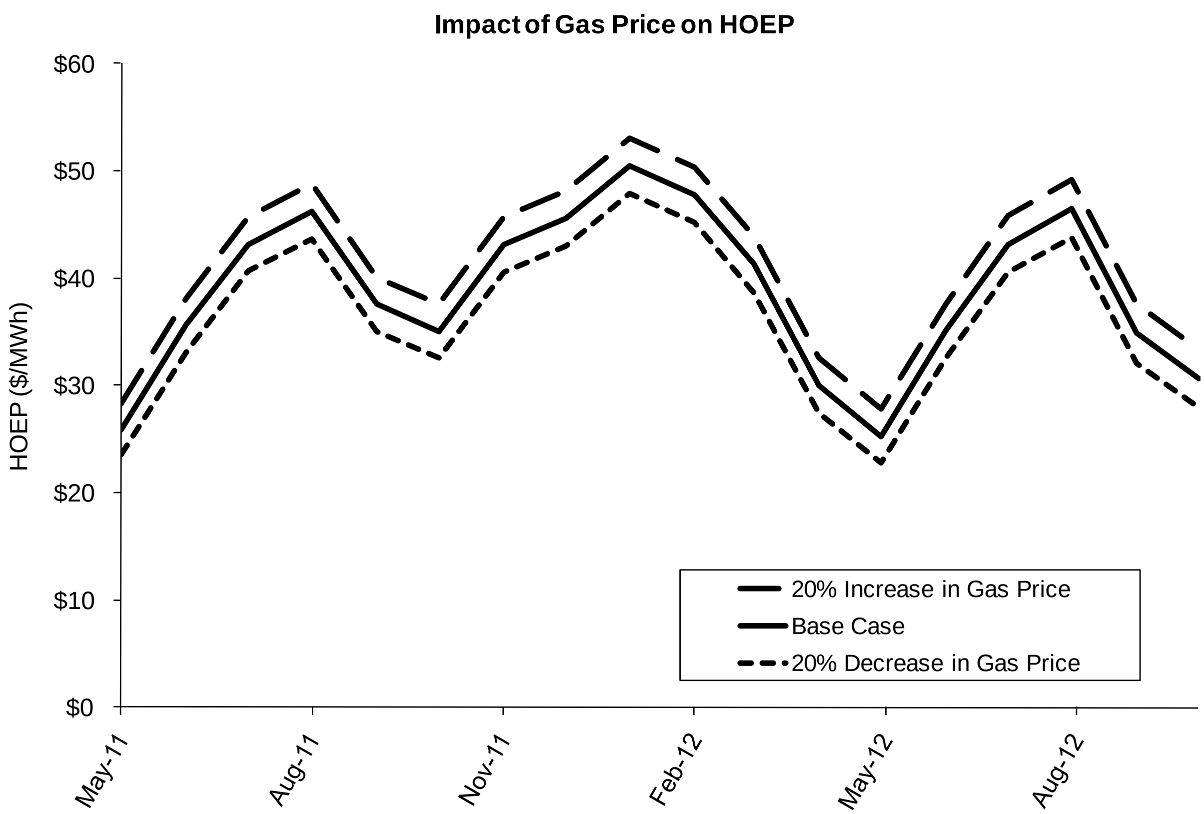
Source: NYMEX

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 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 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 7% when natural gas prices were assumed to be 20% higher than forecast, and decreased by an average of 7% when natural gas prices were assumed to be 20% lower than forecast. HOEP will become more sensitive to increases in gas prices as the amount of coal generation available is limited by plant closures and the CO_2 emission limits.

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



Source: Navigant Consulting

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.

5.4 Impact of Coal Emission Limits

Navigant estimates that the coal plants will significantly undershoot the emissions target of 11.5 million tonnes for 2011 and 2012, without any adders, withholding, or other OPG efforts to limit generation. The base case price forecast takes into account the closure of four large coal units in October 2010, and another two in late 2011, which will limit supply and therefore increase prices. It does not assume any additional measures to limit CO_2 emission limits in 2011 or 2012.

The plant closures are estimated to increase electricity prices by an average of $7/MWh between May 2011 and April 2012.

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 may still occur: with low demand and low gas prices keeping electricity prices low, 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's forecast, the increase is likely to be much greater than it would have been without the CO_2 emission limits.