Ontario Wholesale Electricity Market Price Forecast

For the Period
November 1, 2013 through April 30, 2015

Presented to

Ontario Energy Board

October 11, 2013

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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	Nov 13 - Jan 14	$30.08	$21.46	$25.38	
	Q2	Feb 14 - Apr 14	$23.30	$16.06	$19.39	
	Q3	May 14 - Jul 14	$21.96	$12.72	$16.99	
	Q4	Aug 14 - Oct 14	$21.60	$13.03	$16.92	$19.67
Other	Q1	Nov 14 - Jan 15	$28.78	$19.79	$23.88	
	Q2	Feb 15 - Apr 15	$25.04	$17.37	$20.90	$22.42

Source: Navigant Consulting

Notes

1) The price forecast reflects an average exchange rate of $1.042 CAD between November 2013 and April 2015. The exchange rate forecast is taken from the Bank of Montreal's "Canadian Economic Outlook", issued September 13, 2013.

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 November 1, 2013 through April 30, 2015 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 key forecast assumptions and identifies the information source. 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 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. The outcome of an increase in Ontario's fleet of natural-gas fired generators combined with the retirement of Ontario's coal generation will be to further increase the importance of natural gas generation. 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 (November 2013 – October 2014)*.

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 September 2013 to February 2015* (dated September 3, 2013).

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
2013	Energy (TWh)											11.7	12.7
	Peak Demand (MW)											20,326	21,395
2014	Energy (TWh)	13.4	11.8	12.2	10.7	10.8	11.4	12.2	12.1	10.6	11.3	11.8	12.8
	Peak Demand (MW)	22,282	21,036	20,014	17,472	18,796	22,289	22,834	21,514	19,045	18,096	20,517	21,171
2015	Energy (TWh)	13.2	11.6	12.3	10.7								
	Peak Demand (MW)	22,234	20,967	20,856	18,952								

Source: IESO, *18-Month Outlook Update: An Assessment of the Reliability and Operability of the Ontario Electricity System From September 2013 to February 2015* (September 3, 2013)

[1]1) The price forecast reflects an average exchange rate of $1.042 CAD between November 2013 and April 2015 . The exchange rate forecast is taken from the Bank of Montreal's "Canadian Economic Outlook", issued September 13, 2013.

3.2 Supply Assumptions

The existing generation capacity assumptions are consistent with the IESO's *18-Month Outlook Update* (September 3, 2013). This includes the scheduled retirement of the remaining coal units at Lambton and Nanticoke by the end of Q4 2013, as well as the retirement of the coal units at Thunder Bay by year end 2014. 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. The IESO capacity additions include the Niagara tunnel project, the Atikokan conversion to biomass, and a number of renewable generation projects amounting to 2,600 MW of wind and 300 MW of solar.

Table 2: Major Generation Capacity Additions

Term	Project Name	Resource Type	Capacity (MW)	In-service date
RPP Period	McLean's Mountain Wind Farm	Wind	60	2013-Q4
	Becker Cogeneration Plant	Biomass	8	2013-Q4
	New Third Unit at Little Long	Water	67	2013-Q4
	Lambton Coal Shutdown	Coal	-1016	2013-Q4
	Nanticoke Coal Shutdown	Coal	-1985	2013-Q4
	Bow Lake Phase 1	Wind	20	2014-Q1
	Dufferin Wind Farm	Wind	100	2014-Q1
	Twin Falls	Water	5	2014-Q1
	Niagara Region Wind Farm	Wind	230	2014-Q1
	Nigig Power Corporation	Wind	300	2014-Q1
	Port Dover and Nanticoke Wind Project	Wind	104	2014-Q1
	Haldimand Solar Project	Solar	100	2014-Q1
	Haldimand Wind Project	Wind	149	2014-Q1
	South Kent Wind Project	Wind	270	2014-Q1
	Leamington Pollution Control Plant	Oil	2	2014-Q2
	Amherst Island Wind Project	Wind	75	2014-Q2
	Goulais Wind Farm	Wind	25	2014-Q2
	Bow Lake Phase 2	Wind	40	2014-Q2
	Adelaide Wind Power Project	Wind	40	2014-Q3
	Bornish Wind Energy Centre	Wind	74	2014-Q3
	Grand Bend Wind Farm	Wind	100	2014-Q3
	Grand Valley Wind Farms (Phase 3)	Wind	40	2014-Q3
	Gunn's Hill Wind Farm	Wind	25	2014-Q3
	Silvercreek Solar Park	Solar	10	2014-Q3
	Cedar Point Wind Power Project Phase II	Wind	100	2014-Q3
	Adelaide Wind Energy Centre	Wind	60	2014-Q3
	Bluewater Wind Energy Centre	Wind	60	2014-Q3
	Goshen Wind Energy Centre	Wind	102	2014-Q3
	Jericho Wind Energy Centre	Wind	150	2014-Q3
	Gitchi Animki Bezhig Generating Station	Water	9	2014-Q3
	Gitchi Animki Niizh Generating Station	Water	10	2014-Q3
	Atikokan conversion to biomass	Biomass	205	2014-Q3
	White Pines Wind Farm	Wind	60	2014-Q3
	Liskeard 1	Solar	10	2014-Q3
	Liskeard 3	Solar	10	2014-Q3
	Liskeard 4	Solar	10	2014-Q3
	Northland Power Solar Abitibi	Solar	10	2014-Q3
	Northland Power Solar Empire	Solar	10	2014-Q3
	Northland Power Solar Long Lake	Solar	10	2014-Q3
	Northland Power Solar Martin's Meadows	Solar	10	2014-Q3
	Thunder Bay Coal Shutdown	Coal	-306	2014-Q4
	Armow Wind Project	Wind	180	2014-Q4
	K2 Wind Project	Wind	270	2014-Q4
	Kingston Solar Project	Solar	100	2014-Q4
	Peeshoo Project	Water	7	2015-Q1
	Wahpeestan Project	Water	7	2015-Q1
	Wapoose Project	Water	7	2015-Q1
	Neeskah Project	Water	7	2015-Q1
	New Third Unit at Harmon	Water	78	2015-Q1
	New Third Unit at Kipling	Water	78	2015-Q1
	Trout Lake River Hydroelectric Project	Water	4	2015-Q1

Source: IESO, *18-Month Outlook Update: An Assessment of the Reliability and Operability of the Ontario Electricity System From September 2013 to February 2015* (September 3, 2013)

In addition to the projects in Table 2, the OPA has contracted with renewable energy power producers under the Renewable Energy Standard Offer Program (RESOP) and the Feed-in Tariff (FIT) program. Although there was some attrition of RESOP contract holders who subsequently applied to the FIT program, as of the last quarterly report published by the OPA, updated for the second quarter of 2013, 852 MW remain under contract, of which 802 MW were in commercial operation[2]. Of the 50 MW under development, 36 MW are wind projects, 10 MW are solar PV projects and 4 MW are bio-energy.

As of June 30, 2013, the OPA had executed 1,686 FIT contracts with a total capacity of 4,492 MW. Of these, 690 contracts representing 611 MW have reached commercial operation with the remaining balance being under development. About 68% of the total FIT MWs approved to date are for wind projects, 26% are for solar PV projects, 4% are for hydroelectricity and 1% is bio-energy projects.

There are over 16,000 microFIT projects that have achieved commercial operation, representing 143 MW of capacity. The government allocated another 200 MW of small FIT projects and 50 MW of microFIT projects to the FIT 2.0 procurement. The FIT 3.0 procurement is also now in effect, targeting 30 MW of generation for the remainder of 2013 and 50MW for 2014. Renewable generation under contract with the OPA supplied generation equivalent to approximately 7% of Ontario demand in 2012. This is estimated to increase to 9% by 2013 and 14% in 2014. 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 74% 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

	2009	2010	2011	2012	2013	RPP Year	18 Months
Average monthly MW	9,364	9,461	9,739	9,689	10,479	11,365	11,106
Average monthly capacity	11,378	11,378	11,378	11,628	12,878	12,878	12,878
Annual capacity factor	82.3%	83.1%	85.6%	83.3%	81.4%	88.2%	86.2%

Source: Navigant Consulting analysis of IESO generator disclosure reports.

[2] OPA – A Progress Report on Contracted Electricity Supply 2013 Second Quarter

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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* (May 24, 2013) 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.

Table 4: Ontario Interconnection Limits

Interconnection	Flows Out of Ontario	Flows Into
Manitoba		
Summer	288	288
Winter	300	300
Minnesota		
Summer	150	100
Winter	150	100
Michigan		
Summer	1,900	1,600
Winter	1,910	1,650
New York		
Summer	2,060	1,620
Winter	2,390	1,870
Quebec		
Summer	2,135	2,775
Winter	2,170	2,795

Source: IESO, *Ontario Transmission System*, May 24, 2013

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 November 2013 is C$4.27/MMBtu. The forecast average price over the entire 18-month period is C$4.35/MMBtu. The twelve-month forecast was used to establish the RPP prices in the *RPP Price Report (November 2013 – October 2014)*.

Table 5: Natural Gas Price Forecast

Term	Month	Henry Hub (US $/MMBtu)	Dawn (C$/MMBtu)
RPP Year	Nov-13	$3.69	$3.97
	Dec-13	$3.85	$4.20
	Jan-14	$3.94	$4.39
	Feb-14	$3.95	$4.40
	Mar-14	$3.91	$4.39
	Apr-14	$3.84	$4.27
	May-14	$3.86	$4.31
	Jun-14	$3.89	$4.34
	Jul-14	$3.92	$4.21
	Aug-14	$3.93	$4.23
	Sep-14	$3.93	$4.27
	Oct-14	$3.95	$4.20
Other	Nov-14	$4.03	$4.33
	Dec-14	$4.18	$4.58
	Jan-15	$4.27	$4.69
	Feb-15	$4.24	$4.69
	Mar-15	$4.18	$4.65
	Apr-15	$3.98	$4.21

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 11.5 million tonnes in 2011. 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 12 TWh per year for the period from 2012 through year end 2014 when all coal-fired generation will be retired. With actual CO_2 emissions of 4.2 million tonnes in 2011 and 4.3 million tonnes in 2012, OPG was well below the limit of 11.5 million tonnes. This reduction was 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 a further two units retired at Nanticoke late in 2011. Although OPG 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. Furthermore, the Province announced in January of this year that the retirement date for the remaining coal generation at Lambton and Nanticoke will be advanced one year from 2014, to year end of 2013. 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 1.5 million tonnes in 2013 (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 2013. Given that no emission reduction measures and subsequent supply restrictions are anticipated, the influence on prices is expected to be neutral.

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 higher than average over the last six months (April 2013 – September 2013). 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	Nov 13 - Jan 14	$30.08	$21.46	$25.38	
	Q2	Feb 14 - Apr 14	$23.30	$16.06	$19.39	
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Source: Navigant Consulting

Notes:

1) The price forecast reflects an average exchange rate of $1.042 CAD between November 2013 and April 2015. The exchange rate forecast is taken from the Bank of Montreal's "Canadian Economic Outlook", issued September 13, 2013.

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.

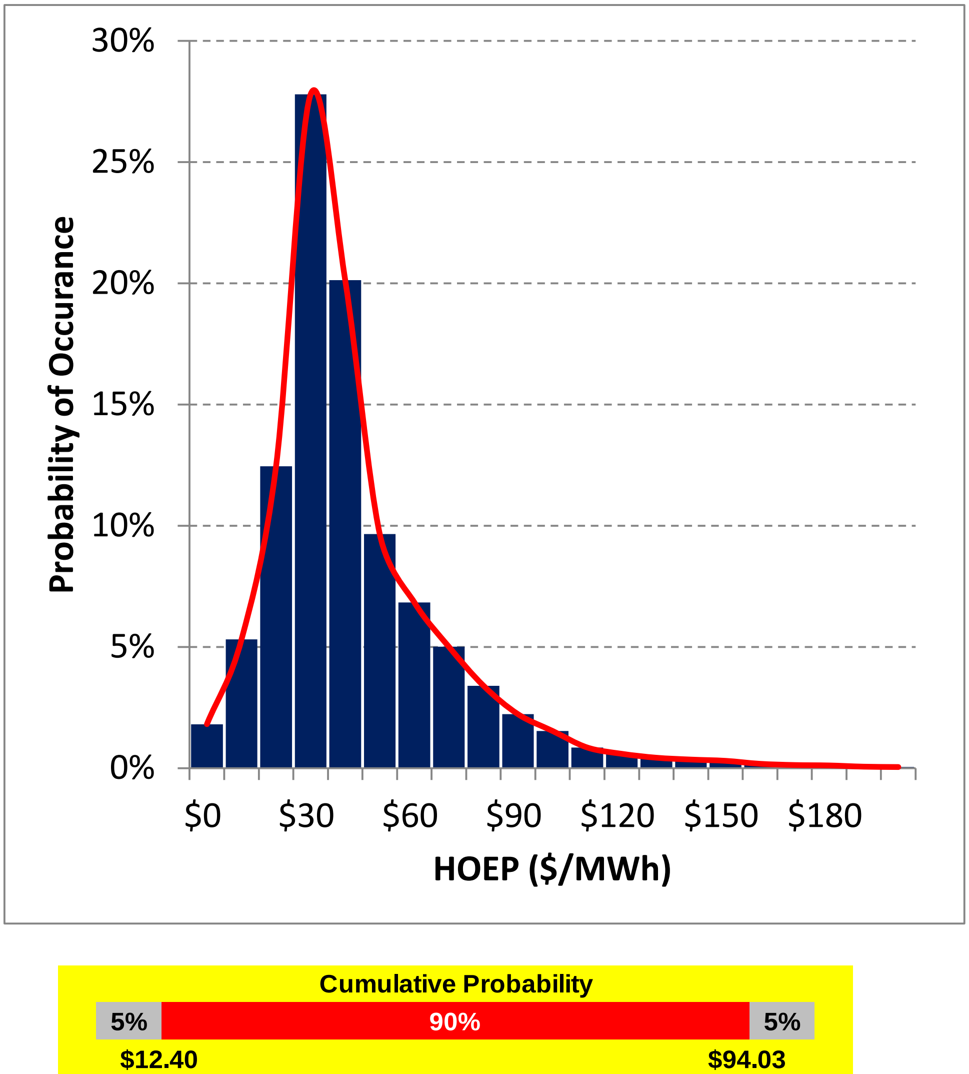
This price forecast is based on market fundamentals and reflects the assumptions used for the forecast from the statistical model. To the degree that actual market variables (gas prices, hourly loads and generator availabilities) are different from our forecast assumptions, market prices are likely to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

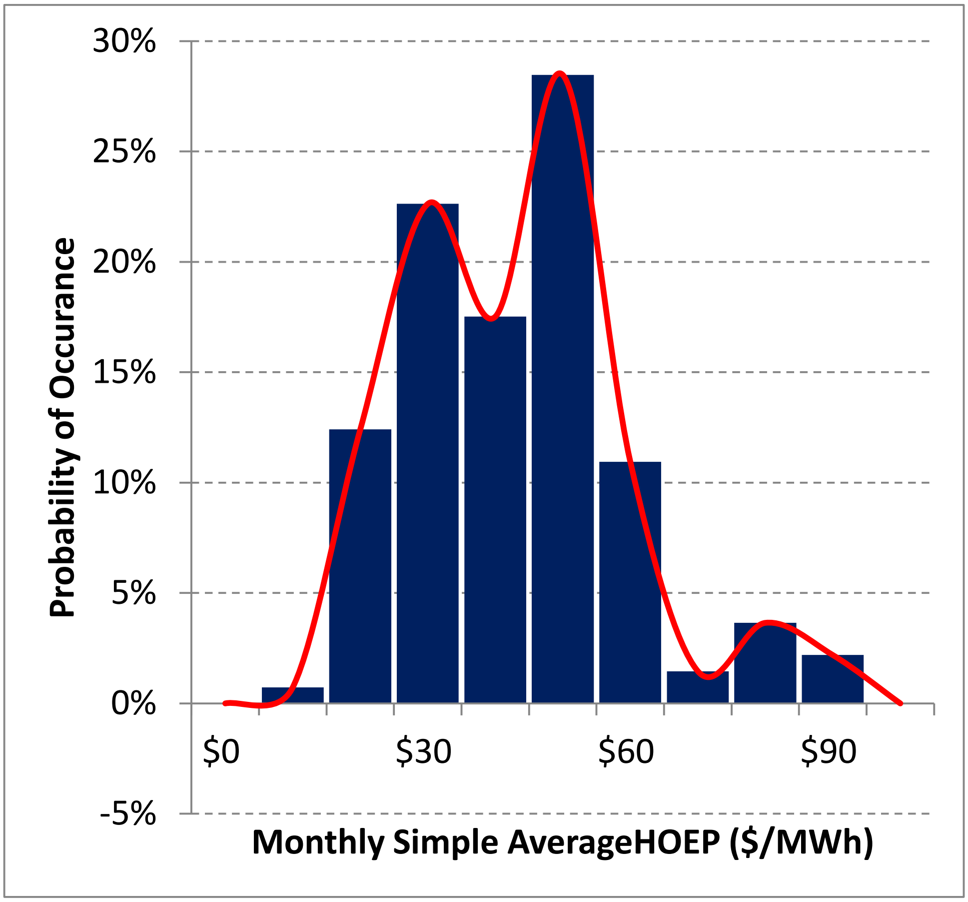
not as skewed as the distribution of hourly prices, Figure 2 demonstrates that even the distribution of monthly prices is skewed to the right.

Figure 1: Historic Distribution of Hourly HOEP



Source: Navigant Consulting analysis of IESO data (May 2002 to September 2013)

Figure 2: Historic Distribution of Monthly Average HOEP



Cumulative Probability		
5%	90%	5%
$20.60		$75.34

Source: Navigant Consulting analysis of IESO data (May 2002 to September 2013)

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 three 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; and (3) generator availabilities. 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 September 3, 2013 *18-Month Outlook Update* forecasts a normal weather summer peak of 22,834 MW and an extreme weather peak of 24,851 MW for the summer of 2014, 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 2013 – October 2014)*. 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.

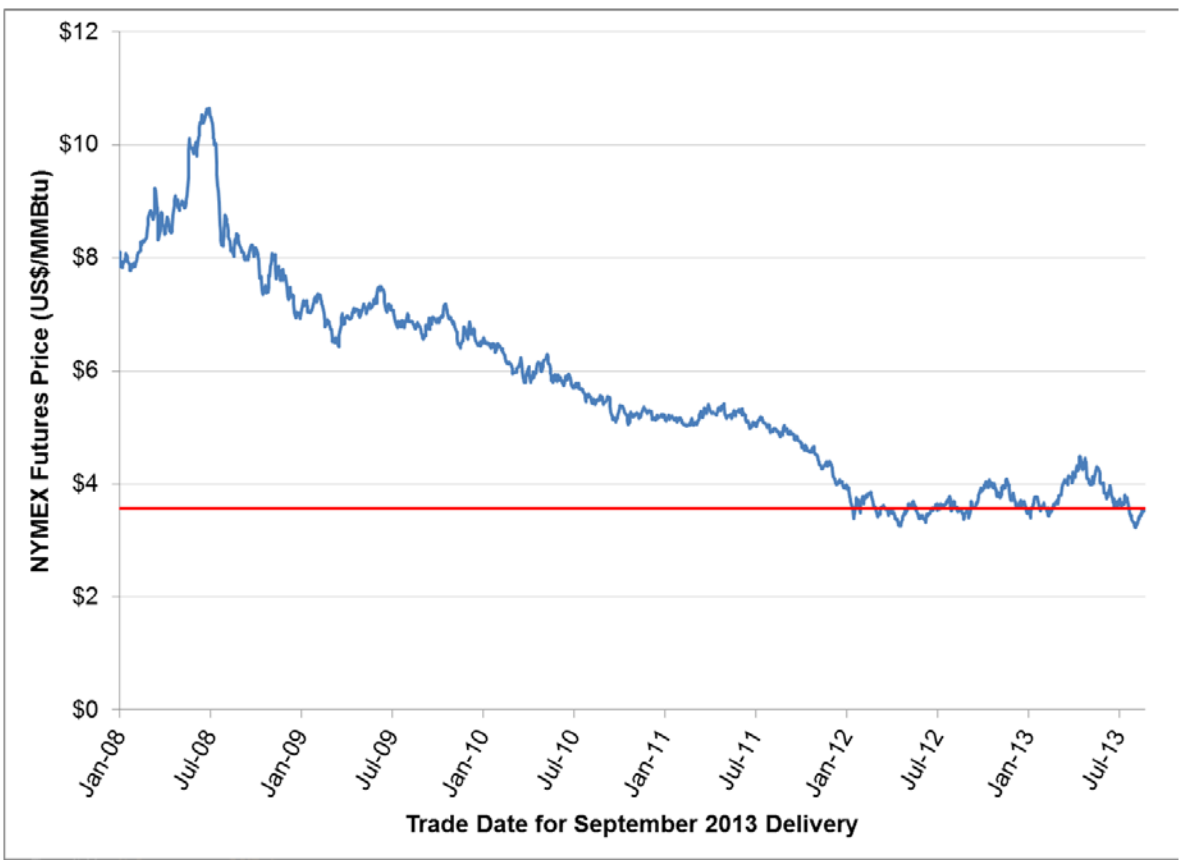
5.2 Fuel Price Forecast Risk

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), GTAA Cogeneration Plant (90 MW) and the York Energy Center (393 MW). There was approximately 5,180 MW of gas-fired generation operating under contract through December 2011 (not including Lennox and the NUGs). This increased to approximately 5,570 MW with the addition of York Energy Center in 2012. 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 September 2013 delivery since January 2008. 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 September 2013 Futures Prices (US$/MMBtu)



Source: NYMEX

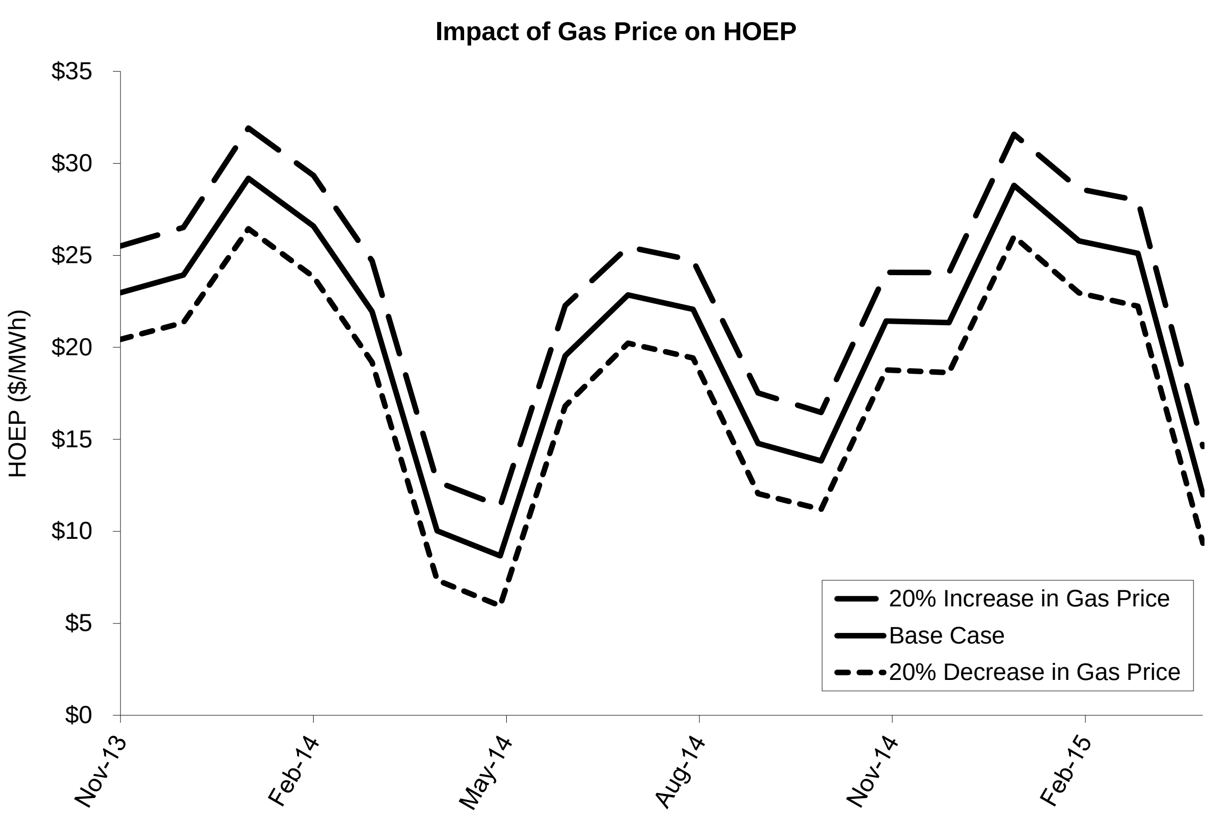
Lennox is the only major Ontario generator which burns oil, but generally residual oil is not its primary fuel. Furthermore, there is a relatively limited amount of oil-fired generation in

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 15% when natural gas prices were assumed to be 20% higher than forecast, and decreased by an average of 15% when natural gas prices were assumed to be 20% lower than forecast. HOEP has become more sensitive to increases in gas prices as the amount of coal generation available declines and the amount of gas generation increases.

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 2.3 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.