# Regulated Price Plan

# Price Report

## May 1, 2010

## to

## April 30, 2011

# Ontario Energy Board

### April 15, 2010

# Executive Summary

This report contains the electricity commodity prices for consumers designated by regulation under the Regulated Price Plan (RPP) for the period May 1, 2010 through April 30, 2011. The prices were developed using the methodology described in the Regulated Price Plan Manual (RPP Manual).

In accordance with legislation, the prices paid for electricity by RPP consumers must be based on forecasts of the cost of supplying them and must be set to recover those costs. RPP prices are reviewed by the Board every six months to determine if they need to be adjusted.

In broad terms, the methodology used to develop the RPP price has two essential steps:

1. Forecasting the total RPP supply cost for the 12 months from May 1, 2010, and
2. Establishing prices to recover the forecast RPP supply cost from RPP consumers over the 12-month period.

The calculation of the total RPP electricity supply cost involves several separate forecasts, including forecasts of:

- the hourly market price of electricity;
- the electricity consumption pattern of RPP consumers;
- the electricity supplied by those assets of Ontario Power Generation (OPG) whose price is regulated;
- the costs related to the contracts signed by non-utility generators (NUGs) with the former Ontario Hydro and the costs associated with certain OPG coal facilities[1];
- the costs of the supply contracts, and conservation and demand management (CDM) initiatives of the Ontario Power Authority (OPA); and
- the net variance account balance (as of April 30, 2010) carried by the OPA.

The overall market-based price for electricity used by RPP consumers reflects both the hourly market price of electricity and the electricity consumption pattern of RPP consumers. Residential consumers, who represent most of the RPP consumption, use relatively more of their electricity during times when total Ontario demand and prices are higher (than the overall Ontario average) and relatively less when total Ontario demand and prices are lower (than the overall Ontario average). That will make the overall market price for RPP consumers higher than the average market price for the entire Ontario electricity market.

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[1] In addition to the contracts with the NUGs, OEFC is also the counterparty to a contingency support agreement with OPG in relation to two of its generation facilities identified in O. Reg. 427/04 (Payments to the Financial Corporation re Section 78.2 of the Act). Payments made to OPG under this agreement are related to the cost recovery mechanism associated with the carbon dioxide ($CO_2$) limits that went into effect January 1, 2009.

## Average RPP Supply Cost

The hourly market price forecast for this computation was developed by Navigant Consulting, Ltd. (Navigant Consulting). The forecast of the simple average market price for 12 months from May 1, 2010 is $36.66 / MWh (3.666 cents per kWh). After accounting for the consumption pattern of RPP consumers, the average market price for electricity used by RPP consumers is forecast to be $39.51 / MWh (3.951 cents per kWh).

The combined effect of the other components of the RPP supply cost is expected to increase this per kilowatt-hour price. The collective impact of the other components is recovered through the Global Adjustment. The Global Adjustment reflects the impact of the NUG contract costs, which are above market prices, the regulated prices for OPG's prescribed baseload nuclear and hydroelectric generating facilities, which may be above or below market prices, and the cost of supply contracts held by the Ontario Power Authority (OPA), most of which are above market prices. Costs associated with CDM initiatives implemented by the OPA are also included. The Global Adjustment also reflects payments made to OPG's Nanticoke and Lambton facilities, under an agreement with the Ontario Electricity Financial Corporation (OEFC), related to the cost recovery mechanism associated with the $CO_2$ limits that went into effect January 1, 2009. The forecast net impact of the Global Adjustment is to increase the average RPP supply cost by $27.72 / MWh (2.772 cents per kWh).

Another factor that needs to be taken into account is that actual prices and actual demand cannot be predicted with absolute certainty; both price and demand are subject to random effects. An additional small adjustment is therefore made to the RPP supply cost to account for the fact that these random effects are more likely to raise than to lower costs. This adjustment was determined to be $1.00 / MWh (0.1 cents per kWh). Without this adjustment, the RPP would be expected to end the year with a small debit variance.

The final adjustment factor is required to "clear" the expected balance in the OPA variance account as of April 30, 2010. The forecast adjustment factor to clear the existing variance balance is a charge (increase in the RPP price) of $1.14 / MWh (0.114 cents per kWh).

The resulting average RPP supply cost, or the RPA, is $69.38 / MWh (6.938 cents per kWh). The above details are summarized in Table ES-1.

**Table ES-1: Average RPP Supply Cost Summary (for the 12 months from May 1, 2009)**

| ***RPP Supply Cost Summary***<br>for the period from May 1, 2010 through April 30, 2011 | | |
|---|---|---|
| Forecast Wholesale Electricity Price | | $36.66 |
| Load-Weighted Price for RPP Consumers ($ / MWh) | | $39.51 |
| Impact of the Global Adjustment ($ / MWh) | + | $27.72 |
| Total Contract Cost | | $69.73 |
| Market Value | | ($42.01) |
| Adjustment to Address Bias Towards Unfavourable Variance ($ / MWh) | + | $1.00 |
| Adjustment to Clear Existing Variance ($ / MWh) | + | $1.14 |
| Average Supply Cost for RPP Consumers ($ / MWh) | = | **$69.38** |

Note: The Market Value of $42.01/MWh is greater than either the Forecast Wholesale Electricity Price or the Load-Weighted Price for RPP Consumers because some generation eligible for Global Adjustment (solar, gas and coal) is only available during peak periods and is sold at a higher market price than the annual average.

Inevitably, there will be a difference between the actual and forecast cost of supplying electricity to all RPP consumers. This difference is referred to as the unexpected variance and will be included in the RPP supply cost for the next RPP period.

RPP consumers are not charged the average RPP supply cost (or the RPA). Rather, they pay prices under price structures that are designed to make their consumption weighted average price equal to the RPA. There are two RPP price structures, one for consumers with conventional meters (Tier Pricing) and one for consumers with eligible time-of-use (or "smart") meters who pay time-of-use (TOU) prices.

## Conventional Meter Regulated Price Plan (Tier Pricing)

The conventional meter RPP has prices in two tiers, one price (referred to as $RPCMT_1$) for monthly consumption under a tier threshold and a higher price (referred to as $RPCMT_2$) for consumption over the threshold. The threshold for residential consumers changes twice a year on a seasonal basis: to 600 kWh per month during the summer season (May 1 to October 31) and to 1000 kWh per month during the winter season (November 1 to April 30). The threshold for non-residential RPP consumers remains constant at 750 kWh per month for the entire year.

The resulting **tier prices** for consumers with conventional meters are:

- $RPCMT_1$ = **6.5** cents per kWh, and.
- $RPCMT_2$ = **7.5** cents per kWh.

Based on consumption over the 12 month period ending February 28, 2010, approximately 55% of RPP consumption was at the lower tier price ($RPCMT_1$) and 45% was at the higher tier price ($RPCMT_2$). Given this split, the weighted average price for conventional meter RPP consumption is forecast to be equal to the RPA.

## Smart Meter Regulated Price Plan (TOU Pricing)

Consumers with eligible time-of-use (or "smart") meters that determine when electricity is consumed during the day will pay under a time-of-use price structure. This currently applies only to consumers of those utilities that have voluntarily implemented time-of-use prices. The prices for this plan are based on three time-of-use periods per weekday[2]. These periods are referred to as Off-Peak (with a price of $RPEM_{OFF}$), Mid-Peak ($RPEM_{MID}$) and On-Peak ($RPEM_{ON}$). The lowest (Off-Peak) price is below the RPA, while the other two are above it.

The resulting **time-of-use (TOU) prices** for consumers with eligible time-of-use meters are:

- $RPEM_{OFF}$ = **5.3** cents per kWh,
- $RPEM_{MID}$ = **8.0** cents per kWh, and
- $RPEM_{ON}$ = **9.9** cents per kWh.

The average price a consumer on TOU prices will pay depends on the consumer's load profile (i.e., how much electricity is used at what time). As discussed above, RPP prices are set so that a consumer with an *average* load profile will pay the same average price under either the tiered or TOU prices, as shown in Table ES-2.[3] This average price is equal to the average RPP supply cost (the RPA) of 6.9¢ / kWh.

**Table ES-2: Price Paid by Average RPP Consumer under Tiered and TOU RPP prices**

| Tiered RPP Prices | Tier 1 | | Tier 2 | Average Price |
|---|---|---|---|---|
| Price | 6.5¢ | | 7.5¢ | 6.9¢ |
| % of Consumption | 56% | | 44% | |
| **Time-of-Use RPP Prices** | **Off-Peak** | **Mid-Peak** | **On-Peak** | **Average Price** |
| Price | 5.3¢ | 8.0¢ | 9.9¢ | 6.9¢ |
| % of Consumption | 54% | 26% | 20% | |

[2] Weekends and statutory holidays have one TOU period: Off-peak.

[3] The percentages of total consumption by TOU period in Table ES-2 are based on consumption data for consumers on TOU pricing in the March 2008 through February 2010 period.

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# 1. INTRODUCTION

Under amendments to the *Ontario Energy Board Act, 1998* (the Act) contained in the *Electricity Restructuring Act, 2004*, the Ontario Energy Board (OEB or the Board) is required to set electricity prices to be charged to consumers that have been designated by legislation or regulation and have not opted for a retailer contract or the spot market price option.[4] The first prices implemented under the Regulated Price Plan (RPP) were effective on April 1, 2005. This report, and the prices contained herein are intended to be in effect on May 1, 2010 and remain in effect until April 30, 2011 barring any required true-up or rebasing.[5] The Board will review the prices in six months to determine if a change is needed.

The Board has prepared a Regulated Price Plan Manual (RPP Manual) to explain how the RPP price is set. This Report describes the way that the Board used the RPP Manual's processes and methodologies to arrive at the RPP prices effective May 1, 2010.

This Report consists of four chapters and one appendix as follows:

- Chapter 1. Introduction
- Chapter 2. Calculating the RPP Supply Cost
- Chapter 3. Calculating RPP Prices
- Chapter 4. Expected Variance
- Appendix A. Modeling Volatility of Supply Cost

## 1.1 Associated Documents

Two documents are closely associated with this Report:

- The *Regulated Price Plan Manual* (RPP Manual) describes in detail the methodology followed in producing the results contained in this Report; and
- The *Ontario Wholesale Electricity Market Price Forecast For the Period May 1, 2010 through October 31, 2011* (Market Price Forecast Report),[6] prepared by Navigant Consulting, contains the Ontario wholesale electricity market price forecast. The document

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[4] The Board's *Standard Supply Service Code* gives RPP-eligible consumers, at their own election and if they have an interval meter, the option to purchase electricity from the IESO-administered spot market.

[5] In accordance with the RPP Manual, price resetting is considered for implementation every six months. If there is a price resetting following a Board review, it will determine how much of a price change will be needed to recover the forecast RPP supply cost *plus or minus* the accumulated variance in the OPA variance account over the next 12 months. In addition to the scheduled six month review, the RPP Manual allows for an automatic "trigger" based adjustment if the unexpected variance exceeds $160 million within a quarter.

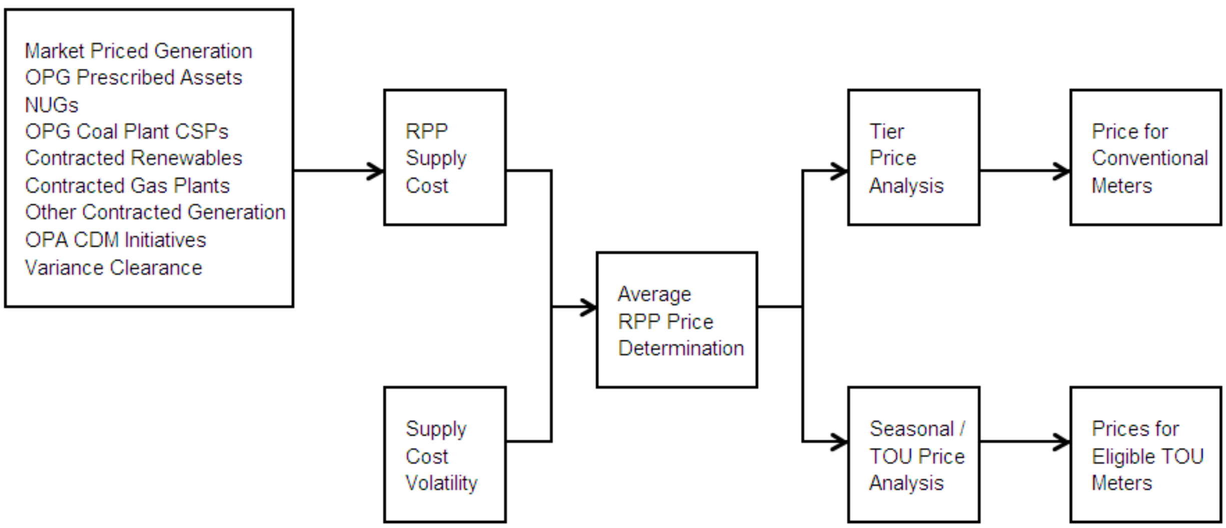
[6] The Market Price Forecast Report is posted on the OEB web site, along with the RPP Price Report, on the RPP web page.

explains the material assumptions which lie behind the hourly price forecast. Those assumptions are not repeated in this Report.

## 1.2 Process for RPP Price Determinations

Figure 1 below illustrates the process for setting RPP prices. The RPP supply cost and the accumulated variance account balance (carried by the OPA) both contribute to the base RPP price, which is set to recover the full costs of electricity supply. The diagram below illustrates the processes to be followed to set the RPP price for both consumers with conventional meters and those with eligible time-of-use meters (or "smart" meters).

**Figure 1: Process Flow for Determining the RPP Price**




Source: RPP Manual

This Report is organized according to this basic process.

## 2. Calculating the RPP Supply Cost

The RPP supply cost calculation formula is set out in Equation 1 below. To calculate the RPP supply cost requires forecast data for each of the terms in Equation 1. Most of the terms depend on more than one underlying data source or assumption. This chapter details the data or assumptions for each of the terms and describes how the data were used to calculate the RPP supply cost. More detail on this methodology is in the RPP Manual.

It is important to remember that all of the terms in Equation 1 are forecasts. In some cases, the calculation uses actual historical values, but in these cases the historical values constitute the best available forecast.

### 2.1 Defining the RPP Supply Cost

Equation 1 below defines the RPP supply cost. The elements of Equation 1 are set out by the legislation and regulations. This equation is further explained in the RPP Manual.

**Equation 1**

$$C_{RPP} = M + \alpha\,[(A - B) + (C - D) + (E - F) + G] + H, \text{ where}$$

- $C_{RPP}$ is the total RPP supply cost;
- M is the amount that the RPP supply would have cost under the Market Rules;
- $\alpha$ is the RPP proportion of the total demand in Ontario;[7]
- A is the amount paid to prescribed (or regulated) generators;[8]
- B is the amount those generators would have received under the Market Rules;
- C is the amount paid to OEFC with respect to its payments under contracts with non-utility generators (NUGs) and the amount to paid to OPG in relation to two of its coal facilities under an agreement with OEFC;
- D is the amount those NUGs would have received under the Market Rules for supplying both electricity and ancillary services;
- E is the amount paid to generators contracted to the OPA that are paid according to their output (i.e., renewable generators);
- F the amount those generators would have received under the Market Rules;

[7] The expression in square brackets is the Global Adjustment; it is applied to the RPP according to the load ratio share represented by RPP consumers, denoted here as $\alpha$.

[8] These are generators designated by regulation and whose output is subject (in whole or in part) to regulated payment amounts that are set by the Board.

- G is the amount paid by the OPA for its other procurement contracts, which includes payments to conventional generators (i.e., natural gas), and for demand response or conservation and demand management (CDM); and
- H is the amount associated with the variance account held by the OPA. This includes any existing variance account balance needed to be recovered (or disbursed) in addition to any interest incurred (or earned).

The forecast per unit RPP supply cost will be the total RPP supply cost ($C_{RPP}$) divided by the total forecast RPP demand. RPP prices will be based on that forecast per unit cost.

## 2.2 Computation of the RPP Supply Cost

Broadly speaking, the steps involved in forecasting the RPP supply cost are:

1. Forecast wholesale market prices;
2. Forecast the load shape for RPP consumers;
3. Forecast the quantities in Equation 1; and
4. Forecast RPP Supply Cost = Total of Equation 1.

In addition to the four steps listed above, the calculation of the total RPP supply cost requires a forecast of the stochastic adjustment, which is not included in Equation 1. The stochastic adjustment is included in the RPP Manual as an additional cost factor calculated outside of Equation 1. Since the RPP prices are always announced by the Board in advance of the actual price adjustment being implemented, it is also necessary to forecast the net variance account balance at the end of the current RPP period (April 30, 2010).[9]

The discussion of data and computation for the forecast of the RPP supply cost will describe each term or group of terms in Equation 1, the data used for forecasting them, and the computational methodology to produce each component of the RPP supply cost.

### 2.2.1 Forecast Cost of Supply Under Market Rules

This section covers the first term of Equation 1:

$$C_{RPP} = \boldsymbol{M} + \alpha\ [(A - B) + (C - D) + (E - F) + G] + H.$$

[9] RPP prices are announced in advance by the Board to provide notification to consumers of the upcoming price change and to provide distributors with the necessary amount of time to incorporate the new RPP prices into their billing systems.

The forecast cost of supply to RPP consumers under the Market Rules depends on two forecasts:

- The forecast of the simple average hourly Ontario electricity price (HOEP) in the IESO-administered market over all hours in each month of the year; and
- The forecast of the ratio of the load-weighted average market price paid by RPP consumers in each month to the simple average HOEP in that month.

The forecast of HOEP is taken directly from the *Wholesale Electricity Market Price Forecast Report*. That report also contains detailed explanations of the assumptions that underpin the forecast such as generator fuel prices (e.g., coal and natural gas). Table 1 below shows forecast seasonal on-peak, off-peak, and average prices. The prices provided in Table 1 are simple averages over all of the hours in the specified period (i.e., they are not load-weighted). These on-peak and off-peak periods differ from and should not be confused with the TOU periods associated with the RPP TOU prices discussed later in this report.

**Table 1: Ontario Electricity Market Price Forecast ($ per MWh)**

| Term | Quarter | Calendar Period | On-Peak | Off-Peak | Average | Term Average |
|---|---|---|---|---|---|---|
| RPP Year | Q1 | May 10 - Jul 10 | $32.47 | $18.99 | $25.21 | |
| | Q2 | Aug 10 - Oct 10 | $41.78 | $26.16 | $33.26 | |
| | Q3 | Nov 10 - Jan 11 | $53.55 | $36.18 | $44.09 | |
| | Q4 | Feb 11 - Apr 11 | $53.84 | $36.22 | $44.31 | $36.66 |
| Other | Q1 | May 11 - Jul 11 | $48.36 | $28.75 | $37.80 | |
| | Q2 | Aug 11 - Oct 11 | $52.04 | $31.51 | $40.84 | $39.32 |

Source: Navigant Consulting, *Wholesale Electricity Market Price Forecast Report*
Note: On-peak hours include the hours ending at 8 a.m. through 11 p.m. Eastern Standard Time (EST) on working weekdays and off-peak hours include all other hours.

The forecasts of the monthly ratios of load-weighted vs. simple average HOEP are based on actual prices between April 2005 and March 2010.

As shown in Table 1, the forecast simple average HOEP for the period May 1, 2010 to April 30, 2011, is $36.66 / MWh (3.666 cents per kWh). The forecast of the load weighted average price for RPP consumers is $39.51 / MWh (3.951 cents per kWh).

RPP consumers accounted for 45.3% of the total electricity withdrawn in the province over the past year (March 2009 through February 2009). Based on the rate of attrition to date, and the departure of the large MUSH sector consumers, it is forecast that RPP consumption will represent about 61 TWh or 44.0% of the total electricity withdrawn in Ontario over the forecast period.

The value of $\alpha$ is therefore 0.440.

### 2.2.2 Cost Adjustment Term for Prescribed Generators

This section covers the second term of Equation 1:

$$C_{RPP} = M + \alpha\ [\boldsymbol{(A - B)} + (C - D) + (E - F) + G] + H$$

The prescribed generators are comprised of the nuclear and baseload hydroelectric facilities of Ontario Power Generation (OPG). The forecast of the dollar amount that the prescribed generators would receive under the Market Rules (quantity B in Equation 1) was calculated as their forecast monthly generation multiplied by their forecast average market revenue in each month. Forecasts of both of these variables were taken from Navigant Consulting's statistical model. For details of the statistical model and the wholesale market price forecast, see Navigant Consulting's Market Price Forecast Report.

The amount paid to OPG's prescribed generation (quantity A in Equation 1) is set by the Board. The payment amounts are currently $54.98/MWh for nuclear generation and $36.66 /MWh for hydro generation:

The nuclear payment amount includes a base rate of $52.98 / MWh, plus $2.00 / MWh for Nuclear "Rider A", as approved by the Board.[10] The Board also approved a change to the incentive mechanism associated with output from the hydroelectric facilities, but the impact of this change on RPP prices is not significant.

Quantity A was therefore forecast by multiplying these fixed payment amounts per MWh, for the prescribed generation facilities, times their total forecast output per month in MWh.

### 2.2.3 Cost Adjustment Term for Non-Utility Generators (NUGs)

This section describes the calculation of the third term of Equation 1:

$$C_{RPP} = M + \alpha\ [(A - B) + \boldsymbol{(C - D)} + (E - F) + G] + H$$

The amount that the NUGs would receive under the Market Rules, quantity D in Equation 1, is their hourly production times the hourly Ontario energy price. These quantities were forecast on a monthly basis, as an aggregate for the NUGs as a whole, in Navigant Consulting's statistical model.

[10] OPG filed an application for an accounting order with the Board on June 9, 2009 which requested a continuation of Nuclear payment "Rider A" past December 31, 2009. This request was approved by the Board on October 6, 2009 (EB-2009-0174).

The OPA has published monthly aggregate payments to the NUGs between September 2007 and February 2010.[11] Although the details of these payments (amounts by recipient, volumes, etc.) are not public, the published information has been used as the basis for forecasting payments in future months. This has been supplemented by information provided by the OEFC and the OPA. This forecast was used to compute an estimate of the total payments to the NUGs under their contracts, or amount C in Equation 1.

Since the beginning of 2009, the NUG component of the Global Adjustment, as published by the OPA, has included an additional component: contingency support payments (CSPs) made in relation to certain OPG coal generation facilities. These payments are explained as follows by OPG in its *2009 Second Quarter Results* report: *"a contingency support agreement [was] established with the Ontario Electricity Financial Corporation ("OEFC") to provide for the continued reliability and availability of OPG's Lambton and Nanticoke generating stations. The agreement was put in place in accordance with the Shareholder Resolution that an appropriate recovery mechanism be established to enable OPG to recover the costs of its coal-fired generating stations following implementation of OPG's carbon dioxide ("CO2") emissions reduction strategy."*[12] Based on the agreement, OPG receives payments through OEFC which make up the difference between OPG's actual costs and its gross revenues for these two plants.[13] The plants' market revenues have been very low in recent months, because of a combination of low market demand and low market prices. As a result, according to OPG's financial reports, these payments were $412 million in 2009.[14] For the purpose of setting the RPP prices for this period, these payments have been forecast by Navigant Consulting to be $215 million based on the following:

- Monthly forecasts of coal generation, based on the historical relationship between market prices and the volume of coal generation (i.e., when market prices are low, coal plants generate less);
- Monthly forecasts of the average hourly market price received by coal generation, based on historical relationships; and
- Estimates of the monthly revenue requirement and unit variable costs, based on historical data on hourly coal generation and hourly market prices, and the actual payments received by OPG in 2009.

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[11] The latest report, *OPA Cash Flows from the Global Adjustment Mechanism (GAM),* was published in February 2010.

[12] See page 8 of OPG's *2009 Second Quarter Results* report at the following: www.opg.com/investor/pdf/2009_Q2_FullRpt.pdf.

[13] According to the agreement, Gross Revenues and Actual Costs are comprised of: (1) *Actual costs* include OM&A, fuel costs (including emission credit/allowances), depreciation, insurance, capital/property taxes, direct corporate support costs, interest on inventory (including fuel), IESO market charges (i.e., uplifts), and biomass costs; (2) *Gross revenues* include all net market revenues (all energy related market revenues, CMSC credits, ancillary service revenues), revenues from emission credits, generation cost guarantee payments, and other non-electricity revenues (i.e., by-products and dock rentals). The agreement is available at: www.opg.com/pdf/OEFC%20Agreement%202009.pdf.

[14] Ontario Power Generation, *Year End Financial Results – 2009*,p. 32.

Until September 30, 2009, OPG had a series of Reliability Must Run (RMR) contracts with the IESO for Lennox Generating Station, a 2,140-MW peaking plant, with the cost recovered through the Uplift charge, not through the Global Adjustment Mechanism. The IESO did not renew the last RMR contract. In January 2010, the Minister of Energy and Infrastructure directed the OPA to negotiate a contract with OPG for the on-going operation of Lennox G.S., on terms similar to those in the contracts with the IESO. For this RPP period, it is assumed that the total annual cost of the Lennox contract will be between $60 and $70 million, that the next contract will expire at the end of September, and that the entire cost of the contract will be recovered through the OPA component of the Global Adjustment between May and September. It is also assumed that the contract will be renewed in October 2010, with the same annual cost spread, but this time spread over the full 12 months.

### 2.2.4 Cost Adjustment Term for Renewable Generation Under Output-Based Contracts with the OPA

This section describes the calculation of the fourth term of Equation 1:

$$C_{RPP} = M + \alpha\ [(A - B) + (C - D) + \boldsymbol{(E - F)} + G] + H$$

Quantities E and F in the above formula refer to generators paid by the OPA under contracts related to output. Generators in this category are renewable generators under the following contracts:

- Renewable Energy Supply (RES) Request for Proposals (RFP) Phases I, II and III,
- the Renewable Energy Standard Offer Program (RESOP),
- the Feed-In Tariff (FIT) Program,
- the Hydroelectric Energy Supply Agreements (HESA) directive, covering new hydro, and
- the Hydro Contract Initiative (HCI), covering existing hydro plants.

The size and generation type of the successful renewable energy projects to date have been announced by the Government and the OPA. The statistical model produced forecasts of additional renewable capacity coming into service during the RPP Period, and the monthly output of both existing and new plants, using either historical values of actual outputs (where available), or estimates based on the plants' capacities and estimated capacity factors. The statistical model also forecasts average market revenues for each plant or type of plant. Quantity F in Equation 1 is therefore the forecast output of the renewable generation multiplied by the forecast average market revenue at the time that output is generated.

Quantity E in Equation 1 is the forecast quantity of electricity supplied by these renewable generators times the fixed price they are paid under their contract with the OPA. The statistical model includes estimates of the fixed prices. In some cases, this is simply the announced contract price (e.g., $420/MWh for solar generation under RESOP). In others, the contract price needs to be adjusted in each year either partially or fully in proportion to inflation. In still others, detailed information on contract prices is not available, and they have been estimated based on publicly-available information (for example, the Ontario Government announced that the weighted average price for Renewable RFP I projects was $79.97 / MWh, but did not announce prices for individual contracts). [15]

### 2.2.5 Cost Adjustment Term for Other Contracts with the OPA

This section describes the calculation of the fifth term of Equation 1:

$$C_{RPP} = M + \alpha\,[(A - B) + (C - D) + (E - F) + \boldsymbol{G}] + H$$

The costs for three types of resources under contract with the OPA are included in G:

1. conventional generation (e.g., natural gas) whose payment relates to the generator's capacity costs;
2. demand side management or demand response contracts; and
3. Bruce Power, which has an output-based contract for generation from its Bruce A nuclear facility, and a price guarantee contract (i.e., floor price) for its Bruce B facility.

The contribution of conventional generation under contract to the OPA to quantity G relates to several contracts:

- The Clean Energy Supply (CES) RFP, which includes conventional generation contracts as well as a 10-MW demand response contract awarded to Loblaws;[16]
- The "early mover" contracts;[17]
- Seven contracts awarded through the Combined Heat and Power (CHP) Phase I RFP;[18]and,
- Five large gas-fired plants (Portlands, Goreway, Greenfield St. Clair and Halton Hills). The first of these, the Portlands Energy Centre, began operation as a simple-cycle plant in June 2008 and has been converted into a combined-cycle plant. Greenfield began commercial operation in October 2008, St. Clair in March 2009, and Goreway in June

[15] For information related to the FIT Price Schedule, see the OPA's dedicated web page at: fit.powerauthority.on.ca/Page.asp?PageID=924&ContentID=10543

[16] Seven facilities holding CES contracts are expected to be operational during this RPP period: the GTAA Cogeneration Facility, the Loblaws Demand Response Program, the Greenfield Energy Centre, the Portlands Energy Centre, the Goreway Station Project, the St. Clair Energy Centre and Halton Hills Generating Station.

[17] On December 14, 2005, the Minister of Energy directed the OPA to negotiate contracts with plants that had entered service since 1998 without a contract. Five facilities signed early mover contracts with the OPA: the Brighton Beach facility, TransAlta's Sarnia facility, and three Toromont facilities. These contracts will remain in force until 2011.

[18] Seven facilities holding CES contracts are expected to be operational during this RPP period: the GTAA Cogeneration Facility, the Loblaws Demand Response Program, the Greenfield Energy Centre, the Portlands Energy Centre, the Goreway Station Project, the St. Clair Energy Centre and Halton Hills Generating Station. The OPA entered into contracts with these facilities pursuant the Ministry of Energy's directive of March 24, 2005.

2009. The Halton Hills Generating Station is expected to come into service in the third quarter of 2010.

The costs of these contracts, for the purpose of calculating the RPP supply cost, are based on an estimate of the contingent support payments to be paid under the contract guidelines. The contingent support payment is the difference between the net revenue requirement (NRR) stipulated in the contracts and the "deemed" energy market revenues. The deemed energy market revenues were estimated based on the deemed dispatch logic as stipulated in the contract and the wholesale market price forecast that underpins this RPP price setting activity. The NRRs and other contract parameters for each contract have been estimated based on publicly available information. For example, the average NRR for the CES contracts was announced by the Government to be $7,900 per megawatt-month.[19]

The cost to the OPA of any additional conservation and demand management (CDM) initiatives is also captured in term G of Equation 1. The OPA is currently offering or planning to offer several CDM initiatives over the next 12 months. These programs generally fall into three categories: Mass Market programs, Commercial / Institutional Market programs and Industrial Market programs, and are based on various directives issued by the Ministry of Energy to the OPA between June 15, 2005 and December 8, 2009. Some OPA conservation-related costs are not recovered through the Global Adjustment and therefore do not impact the Global Adjustment (i.e., are not included in term G of Equation 1). Such costs are instead recovered through the OPA Fee as part of the Regulatory charge.

The Bruce Power contract initially stipulated that output from the Bruce A facility would be paid a base price of $57.37 / MWh, indexed to inflation, plus fuel costs. As of April 1, 2008, the base price was increased by $2.11/MWh, to $59.48 / MWh.[20] At today's fuel prices and including inflation adjustments since the contract went into effect, the average price during the upcoming RPP period is estimated to be approximately $69/MWh. Under the agreement, Bruce Power will be paid a monthly contingent support payment if its actual revenues are less than contract revenues or it will make a revenue sharing payment to the OPA if actual revenues are greater than contract revenues.

The Bruce Power contract also stipulates that output from the Bruce B facility be guaranteed a floor price of $45/MWh, indexed to inflation, over a calendar year. Adjustments for inflation are made on an annual basis. For the upcoming RPP period, the average floor price is forecast to be approximately $49 / MWh. Payments are calculated on both a monthly and an annual basis, with the result that all of the monthly payments made in each calendar year through 2008 were clawed back at the beginning of the following year. Navigant Consulting estimates that only a small portion of the monthly payments made in 2009 were clawed back, and none of the

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[19] Given the ministerial directive to the OPA, the NRR for the "early movers" was assumed to be the same.

[20] http://www.powerauthority.on.ca/Page.asp?PageID=5024&ContentID=6572&SiteNodeID=237 The "base" (or "reference") price was increased due to the agreement involving the expansion of the Bruce A refurbishment project.

monthly payments to be made during the upcoming RPP period are expected to be clawed back.

### 2.2.6 Estimate of the Global Adjustment

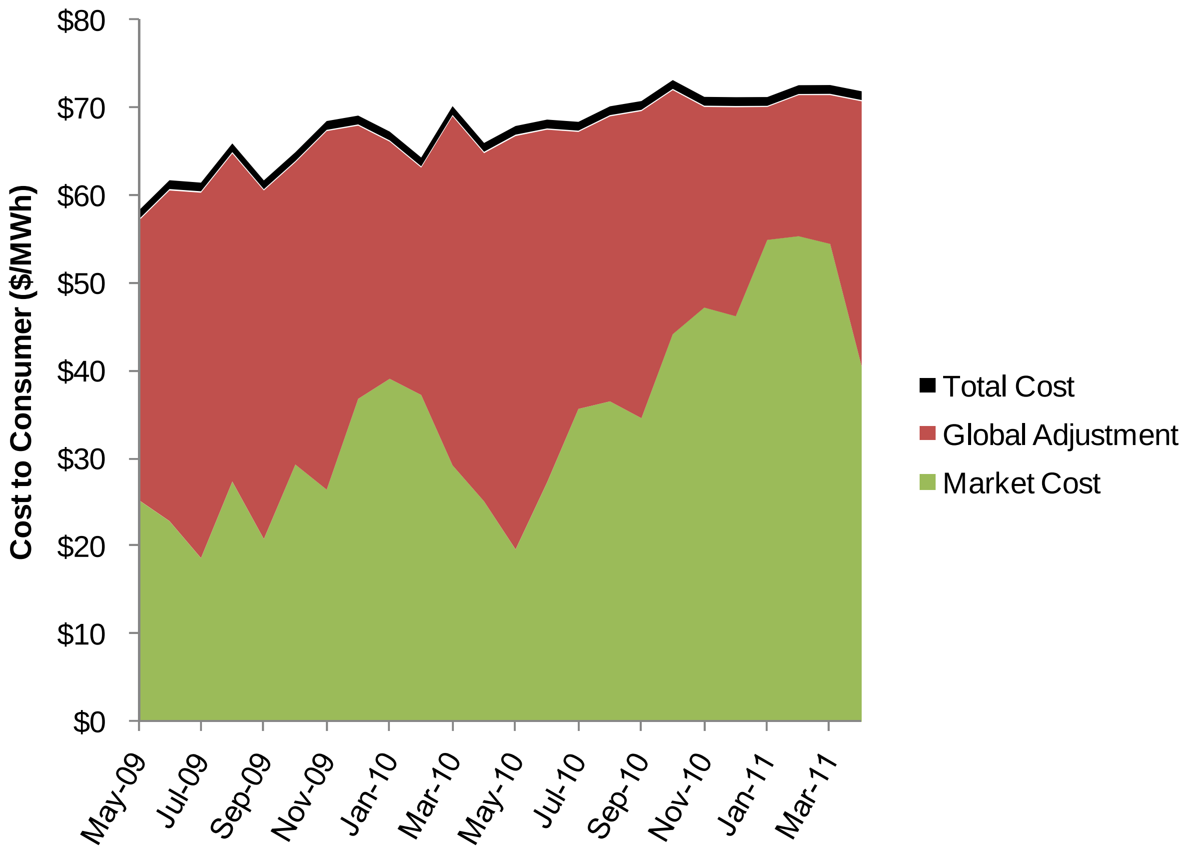
The overall impact of the central term in Equation 1 – $\alpha\ [(A - B) + (C - D) + (E - F) + G]$ – is forecast to increase the RPP unit cost by $27.72 / MWh (2.772 cents per kWh). This essentially represents the forecast of the average Global Adjustment cost per unit payable by RPP consumers over the period from May 1, 2010 to April 30, 2011.

The Global Adjustment represents the difference between the total contract cost of the various contracts it covers (for Ontario Power Generation nuclear and prescribed hydro, Bruce nuclear, gas plants, renewable generation, OPG coal, CDM, etc.) and the market value of the contracted generation. The Global Adjustment therefore changes for two reasons:

- changes in the contracts it covers, or
- fluctuations in the market value of the contracted generation.

This is illustrated in Figure 2, which shows how the Global Adjustment has changed, and is expected to change, over the previous (May 2009 to April 2010) and upcoming (May 2010 to April 2011) RPP periods. Consumers pay the full cost of the contracts covered by the Global Adjustment, either through market costs or through the Global Adjustment itself. The Global Adjustment fluctuates as market prices rise and fall, but the general trend in the total cost (market cost plus Global Adjustment) has been a steady increase.

**Figure 2: Components of the Global Adjustment**




The upward trend in total cost is driven by several factors that have been previously discussed in this report:

- Development of new gas generating capacity, such as the Thorold and Halton Hills plants due to come into service in the upcoming RPP period (Section 2.2.5).
- Development of new renewable generation, under the RES, RESOP and FIT programs (Section 2.2.4).
- Increases in the rates paid for nuclear generation and OPG's prescribed hydro generation; although the increases are small in percentage terms, the volumes are large (Section 2.2.2).
- New contracts for existing generation, including
    - support payments for OPG's coal plants (Section 2.2.3);
    - fixed-price contracts for existing hydro generation (Section 2.2.4);
    - the transfer of Lennox's contract from the IESO (with the costs recovered through the uplift, which is not included in the Regulated Price Plan) to the OPA (with the costs recovered through the Global Adjustment) (Section 2.2.3).
- Increases in the cost of conservation and demand management (Section 2.2.5).

### 2.2.7 Cost Adjustment Term for OPA Variance Account

This section describes the calculation of the sixth term of Equation 1:

$$C_{RPP} = M + \alpha\ [(A - B) + (C - D) + (E - F) + G] + \boldsymbol{H}$$

The cost adjustment term for the OPA variance account consists of two factors. The first is the forecast interest costs associated with carrying any RPP-related variances incurred during the upcoming RPP period (May 2010 – April 2011). The second represents the price adjustment required to clear (i.e., recover or disburse) the existing RPP variance and interest accumulated over the previous RPP period.

The first term discussed above is small, as any interest expenses incurred by the OPA to carry debit variances in some months are generally offset by interest income the OPA receives from carrying credit balances in other months. In addition, the interest rate paid by the OPA on the variance account is relatively low.

The second term is significant. It represents the price adjustment necessary to clear the total net variance accumulated since the RPP was introduced on April 1, 2005 through to the beginning of this RPP Period. As of April 30, 2010 the net variance account balance is expected to be a negative balance of approximately $69 million including interest.

A variance clearance factor has been calculated that is estimated to bring the variance account to approximately a zero balance over the twelve month period, after taking into account both the changes in total RPP consumption and the Final RPP Variance Settlement Amount payments expected as of April 30, 2010. This variance clearance factor has changed from a *credit* of 0.186 cents per kWh in the previous RPP Price report to a *charge* of 0.114 cents per kWh. This change is primarily the result of higher-than-forecast Global Adjustment costs (as discussed above), which moved the variance account balance from a positive to a negative amount. The variance clearance factor increases the average RPP supply cost by the amount of the charge: $1.14 / MWh (0.114 cents per kWh).

## 2.3 Correcting for the Bias Towards Unfavorable Variances

All the supply costs discussed in section 2.2 are based on a forecast of the HOEP. However, actual prices and actual demand cannot be predicted with absolute certainty. Calculating the total RPP supply cost therefore needs to take into account the fact that volatility exists amongst the forecast parameters, and that there is a slightly greater likelihood of negative or unfavourable variances than favourable variances. For example, because nuclear generation plants tend to operate at capacity factors between 80% and 90%, these facilities are more likely to "under-generate" (due to unscheduled outages) than to "over-generate" (i.e., there is 10-20%

upside versus 80-90% downside on the generator output). Similarly, during unexpectedly cold or hot weather, prices tend to be higher than expected as does RPP consumers' demand for electricity. The net result is that the RPP would be "expected" to end the year with a small unfavourable variance in the absence of a minor adjustment to reflect the greater likelihood of unfavourable variances. This adjustment term is referred to as the "stochastic adjustment". The term stochastic is a reference to the use of probabilistic modeling techniques in determining this adjustment.

These unfavourable variances not only have an effect on the market priced component of the RPP supply cost, but also on the Global Adjustment component as well. For example, in the scenario of nuclear generation used in the previous paragraph, an unforeseen decline in OPG's nuclear production will not only have an impact on the market price because more expensive generation alternatives are required to fill the void, but terms A and B from Equation 1 are also affected. Likewise an unforeseen decline in Bruce Power's nuclear production would have a similar impact on market prices, in addition to an impact on term G in Equation 1. For a detailed discussion of methodology used to model the unfavourable variances please see Appendix A of this report.

Inclusive of all the factors discussed above, and in Appendix A, the necessary stochastic adjustment was determined to be $1.00 / MWh (0.1 cents per kWh). This amount is included in the price paid by RPP consumers to ensure that the "expected" variance at the end of the RPP year is zero.

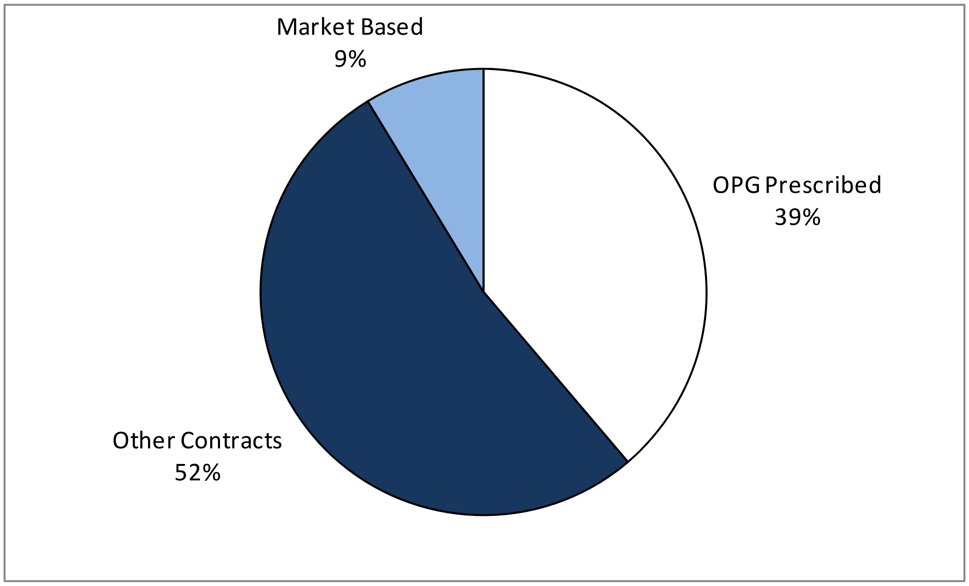
## 2.4 Total RPP Supply Cost

With the stochastic adjustment taken into consideration, the total RPP supply cost is estimated to be approximately $4.2 billion.[21] Figure 3 3 breaks this supply cost into the four major cost streams. Since the forecast market price is well below the "floor" price in the contract with Bruce Power for its Bruce B facilities, those facilities are categorized under "Other Contracts". OPG's Lambton and Nanticoke coal plants are also included in "Other Contracts" because of the agreement with the OEFC which ensures OPG recovers its costs on a monthly basis.

Figures 2 and 3 below illustrate different concepts. Figure 3 shows the expected breakdown of *physical electricity* (i.e., kilowatt-hours) supplied by each of the four generation categories (including CDM) during the upcoming RPP period. This includes all Ontario generation, not just that used by RPP consumers.

[21] The total cost figure is net of the forecast variance account balance as of April 30, 2010.

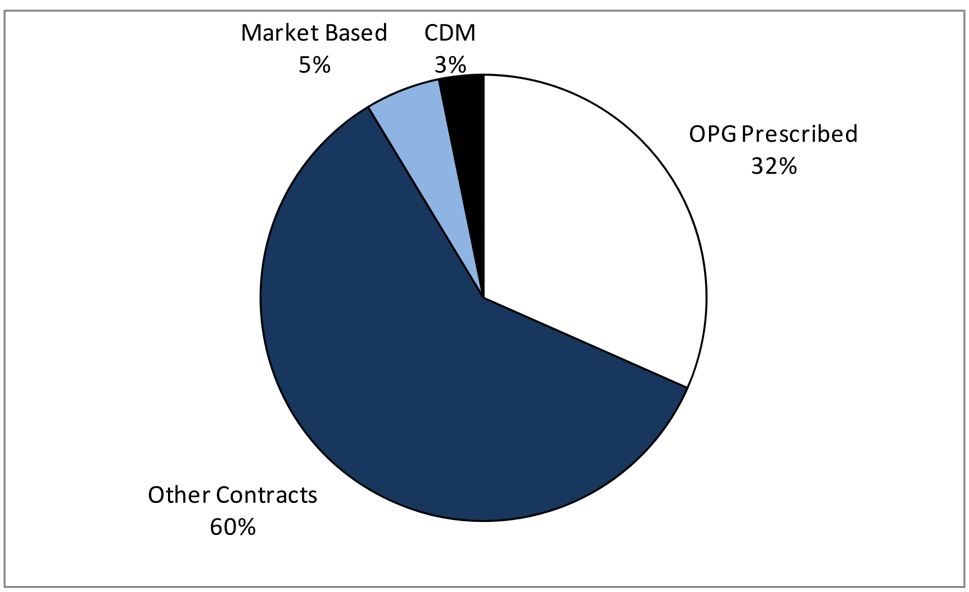
**Figure 3: Ontario Generation by Category (% of kWh)**




Source: Navigant Consulting

Figure 4 shows the expected breakdown of the RPP's *total cost* (exclusive of the variance clearance factor and the stochastic adjustment factor). Costs are allocated based on the projected revenue of each category of generation at the time of consumption. These costs are then adjusted to account for the impact of the relevant regulated or contract terms that affect the ultimate price received by the generators in each of the three non-market based generation categories. These adjustments are also reflected in the Global Adjustment as shown in Table 2 on the following page.

**Figure 4: Components of Total RPP Supply Cost (% of $)**




Source: Navigant Consulting

The proportions shown in the two figures above may be quite different, because they are illustrating different things. For example, while OPG Prescribed (or regulated) generation is expected to account for 39% of Ontario generation output, it is expected to contribute only 32% of the total RPP supply cost, after taking into account differences in usage patterns of RPP consumers compared to the market as a whole, as well as the regulated prices for these generation facilities.

The following table itemizes the various steps discussed above to arrive at the average RPP supply cost of $69.38 / MWh. This average supply cost corresponds to an average RPP price, which is referred to as RPA, of 6.938 cents per kWh.

**Table 2: Average RPP Supply Cost Summary**

| ***RPP Supply Cost Summary*** for the period from May 1, 2010 through April 30, 2011 | | |
|---|---|---|
| Forecast Wholesale Electricity Price | | $36.66 |
| Load-Weighted Price for RPP Consumers ($ / MWh) | | $39.51 |
| Impact of the Global Adjustment ($ / MWh) | + | $27.72 |
| Total Contract Cost | | $69.73 |
| Market Value | | ($42.01) |
| Adjustment to Address Bias Towards Unfavourable Variance ($ / MWh) | + | $1.00 |
| Adjustment to Clear Existing Variance ($ / MWh) | + | $1.14 |
| Average Supply Cost for RPP Consumers ($ / MWh) | = | **$69.38** |

Source: Navigant Consulting

# 3. Calculating the RPP Price

The previous chapter calculated a forecast of the total RPP supply cost. Given the forecast of total RPP demand, it also produced a computation of the average RPP supply cost and the average RPP price, RPA (6.938 cents/kWh). This chapter explains how prices are determined for the tiers, $RPCM_{T1}$ and $RPCM_{T2}$ and the TOU prices, $RPEM_{ON}$, $RPEM_{MID}$, and $RPEM_{OFF}$.

## 3.1 Setting the Tier Prices for RPP Consumers with Conventional Meters

The final step in setting the price for RPP consumers with conventional meters is to determine the tier prices. For these consumers, there is a two-tiered pricing structure: $RPCM_{T1}$ (the price for consumption at or below the tier threshold) and $RPCM_{T2}$ (the price for consumption above the tier threshold). The tier threshold is an amount of consumption per month.

The tier prices are calculated so that the average per unit revenue generated is equal to the RPA. This is achieved by maintaining the ratio between the original upper and lower tier prices (i.e., the ratio between 4.7 and 5.5 cents per kWh) and forecasting consumption above and below the threshold in each month of the RPP.

The resulting **tier prices** are:

- $RPCM_{T1}$ = **6.5** cents per kWh, and.
- $RPCM_{T2}$ = **7.5** cents per kWh.

## 3.2 Setting the TOU Prices for Consumers with Eligible Time-of-Use Meters

The average RPP price for consumers with eligible time-of-use meters is the same as that for conventional meters, the RPA.[22] For those consumers whose distributors have chosen to make time-of-use (TOU) prices available, three separate prices will apply. The times when these prices apply varies by time of day and season, as set out in the RPP Manual. There are three price levels: On-peak ($RPEM_{ON}$), Mid-peak ($RPEM_{MID}$), and Off-peak ($RPEM_{OFF}$). The load-weighted average price must be equal to the RPA, as was the case for the conventional meter RPP prices.

As described in the RPP Manual, the first step is to set the Off-peak price, or $RPEM_{OFF}$. This price reflects the forecast market price during that period, including the allocated global adjustment and the variance clearance factor. The Mid-peak price, $RPEM_{MID}$, is similarly set. After these two prices are set, and given the forecast levels of consumption during each of the

[22] In future years, when experience with time-of-use meters produces a more accurate load shape for consumers with eligible time-of-use meters, the average prices could differ, depending on how different the actual load shape of the time-of-use meter consumers is from the other RPP consumers.

three periods, the On-peak price, $RPEM_{ON}$, is determined by the requirement for the load-weighted average of TOU prices to equal the RPA.

The RPP Manual specifies that the various components of Global Adjustment costs are allocated to TOU consumption periods based on the type of cost. The costs associated with OPG's regulated facilities, Bruce Power's nuclear plants, renewable generation and CDM costs related to Conservation programs are allocated uniformly across all consumption. The remaining portion of the CDM cost is allocated only to On-peak consumption, as the purpose of the Demand Management portion of CDM is to ensure uninterrupted supply during peak times. Contingent support payments to the coal and gas plants, as well as payments to Lennox, are allocated to the three periods based on the amount of generation in each period over the past twelve months (April 2009 – March 2010). The NUG component of the GA (excluding the coal component) is allocated to both Mid-peak and On-peak consumption, as these generators tend to serve non-Off-peak consumption. As well, approximately one-quarter of the stochastic adjustment was allocated to the Mid-peak price and three-quarters was allocated to the On-peak price as this is when the majority of the risks being covered by the adjustment tend to be borne.

The resulting **time-of-use prices** are:

- $RPEM_{OFF}$ = **5.3** cents per kWh
- $RPEM_{MID}$ = **8.0** cents per kWh, and
- $RPEM_{ON}$ = **9.9** cents per kWh.

As defined in the RPP Manual, the time periods for time-of-use (TOU) price application are defined as follows:

- *Off-peak* period (priced at $RPEM_{OFF}$):
  - *Winter and summer weekdays*: 9 p.m. to midnight and midnight to 7 a.m.
  - *Winter and summer weekends and holidays*:[23] 24 hours (all day)
- *Mid-peak* period (priced at $RPEM_{MID}$)
  - *Winter weekdays (November 1 to April 30)*: 11 a.m. to 5 p.m.
  - *Summer weekdays (May 1 to October 31)*: 7 a.m. to 11 a.m. and 5 p.m. to 9 p.m.
- *On-peak* period (priced at $RPEM_{ON}$)
  - *Winter weekdays*: 7 a.m. to 11 a.m. and 5 p.m. to 9 p.m.
  - *Summer weekdays*: 11 a.m. to 5 p.m.

[23] For the purpose of RPP time-of-use pricing, a "holiday" includes the following days: New Year's Day, Family Day, Good Friday, Christmas Day, Boxing Day, Victoria Day, Canada Day, Labour Day, Thanksgiving Day, and the Civic Holiday. When any holiday falls on a weekend (Saturday or Sunday), the next weekday following is to be used in lieu of that holiday.

The above times are given in local time (i.e., the times given reflect daylight savings time in the summer). They reflect changes in the TOU periods that were effective November 1, 2009.

The average price for a consumer on time-of-use prices depends on the consumer's load profile (i.e., how much electricity is used at what time). The load profile assumed for TOU consumers is different from the load profile for non-TOU RPP consumers. RPP prices are set so that a TOU consumer with a typical TOU load profile will pay the same average price as an RPP consumer that pays the tiered prices with a typical (non-TOU) load profile, as shown in Table 3 below. This average price is equal to the average RPP supply cost (the RPA) of 6.9¢ / kWh.

**Table 3: Price Paid by Average RPP Consumer under Tiered and TOU RPP prices**

| Tiered RPP Prices | Tier 1 | | Tier 2 | Average Price |
|---|---|---|---|---|
| Price | 6.5¢ | | 7.5¢ | 6.9¢ |
| % of Consumption | 56% | | 44% | |
| **Time-of-Use RPP Prices** | **Off-Peak** | **Mid-Peak** | **On-Peak** | **Average Price** |
| Price | 5.3¢ | 8.0¢ | 9.9¢ | 6.9¢ |
| % of Consumption | 54% | 26% | 20% | |

# 4. Expected Variance

After RPP prices are set, the monthly expected variance can be calculated directly. The variance clearance factor is set so that the expected variance balance at the end of the RPP period will be as close as possible to zero. However, the variance balance is not expected to decline smoothly; the amount of the variance balance cleared is expected to vary significantly from month to month for several reasons:

- Variance clearance will tend to be higher in months when RPP volumes are higher (i.e., summer and winter) and lower when volumes are lower (i.e., spring and fall).

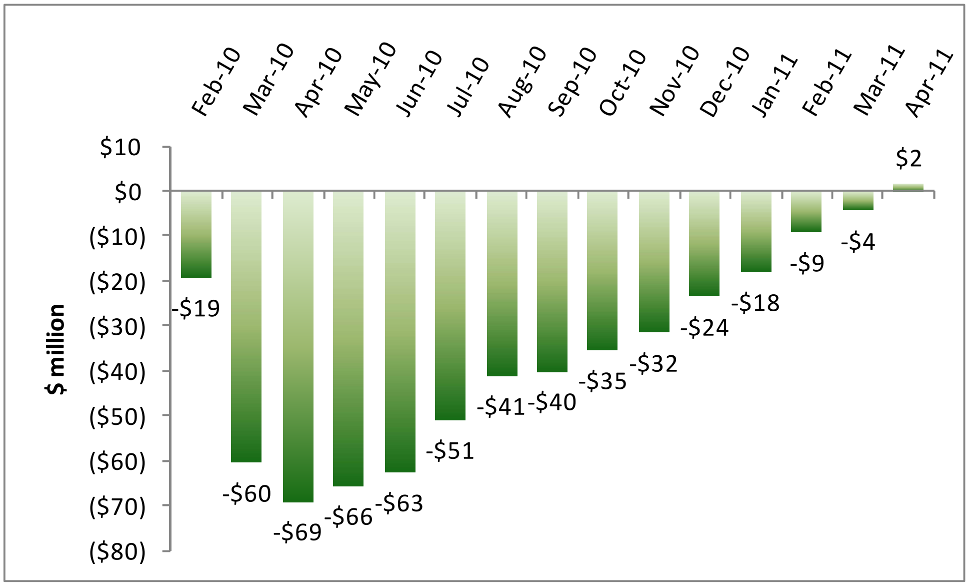
- While there is only technically a single average RPP price (or RPA) in this report, the residential thresholds are higher in winter (1000 kWh) than in summer (600 kWh). This means that the average price most RPP consumers pay will be lower in winter than in summer, because they will have less consumption at the higher tiered price in the winter. Thus, variance clearance will vary from summer to winter.

- The HOEP is projected to be higher in some months (especially summer) and lower in others (especially the shoulder seasons), but RPP prices remain constant. This will be partially offset by changes in the Global Adjustment. Thus, variance clearance will vary by month, depending on market prices.

The combined effect of these factors is shown in Figure 5. The values in each month of Figure 5 represent the total expected balance in the OPA variance account at the end of each month.

Because the RPP prices are rounded to the nearest tenth of a cent, the amount of revenue to be collected cannot be adjusted to exactly clear the variance account. In this case, the new RPP prices given above are expected to collect slightly more than the RPP supply cost, leaving an "expected" balance of $1.5 million in the variance account at the end of the RPP period. However, any decrease in the RPP prices would lead to an even larger under-collection. The RPP prices are therefore set to bring the variance balance as close as possible to zero.

**Figure 5: Expected Monthly Variance Account Balance ($ million)**




Source: Navigant Consulting

# Appendix A – Modeling Volatility of Supply Cost

## Introduction

This section describes the methodology used to model variances from the static forecast RPP supply cost.

RPP supply comes from three sources: those under contract, those that are regulated, and those priced in the IESO-administered market. Sources subject to a Board order are the supply from the regulated OPG assets (baseload hydroelectric and nuclear). Sources under contract include supply from existing NUGs that are under contracts now held by the OEFC; and from any contracts, such as the results of the current RFPs, which are between the suppliers and the OPA.

The expected variance of the RPP supply cost is modeled by considering the factors subject to random variation, and simulating that variation. For each simulation, the effect on the RPP supply cost is determined and the expected variance of RPP supply cost is calculated against the static forecast.

The RPP supply cost can be influenced by several factors subject to random variation. These factors include the quantity of supply from the regulated assets and other contracted sources, the level of demand from RPP eligible consumers, and the Ontario market price.[24]

The interaction among these factors can be complex, because the first two, supply and demand conditions, can affect the third, the Ontario electricity market price. Navigant Consulting has modeled this complex relationship using a combination of econometric and statistical techniques. These have been applied to the supply from the nuclear generation assets (both OPG and Bruce Power), the demand from consumers in Ontario, and the market price of electricity.

With the exception of the contract held with Bruce Power, the variance of supply from the OPA contracts and the NUGs was not modeled. The NUGs' technology, diverse number of resources and fuel sources make them less subject to variability than the other sources of RPP supply. For similar reasons, the variance in supply from the sources contracted to OPA is also expected to be subject to less variability.

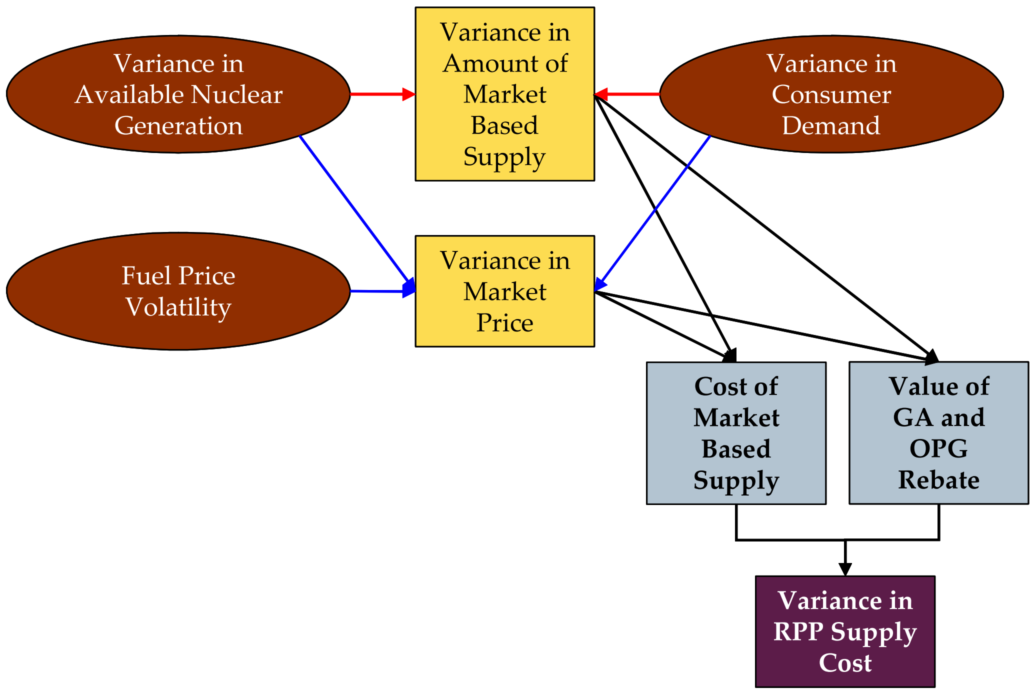
## The Model of Supply Cost Variance

Figure 6 shows the relationships among the modeled factors and their variance. This is a simplified diagram to show the interaction among these factors. In the explanation of the diagram, the assumption used was that the cost of supply from the regulated assets is lower

[24] Variations in fuel prices, such as natural gas, can have a significant influence on the Ontario electricity market price and hence the RPP supply cost.

than the cost of supply from the IESO-administered markets. The explanation will also track the case of a decrease in the amount of that supply below its forecast level and that of an increase in demand for RPP supply above the forecast level. The reverse of the effects on price can be expected if these cases are reversed.

**Figure 6: Diagram of Supply Cost Variance**




Source: Navigant Consulting

The factor in the upper left of Figure 6 shows the amount of supply from nuclear generating assets in the Province. Nuclear generation in Ontario can be broken down into two categories, OPG's regulated assets, and that from Bruce Power. Any deviation of this amount from forecast creates a deviation in the total supply of electricity generated in Ontario and the amount available for RPP supply. A reduction in total supply of nuclear generation in turn affects the market price, because it reduces the amount of lower cost generation available and therefore forces an increased use of larger amounts of more expensive generation. The market price (or HOEP) will therefore increase with a decrease in the amount of supply available from nuclear assets.

The impact on the market price as a result of a decrease in available nuclear supply is not the only effect on the RPP supply cost however. A deviation in the amount of supply from the nuclear assets changes the quantity of electricity available at the regulated rates. The amount of RPP supply to be obtained through and priced (at HOEP) in the IESO-administered markets is the residual of the demand after the supply from the regulated assets, NUG contracts, and any contracts the OPA has entered into with generators. A decrease in the supply from the nuclear assets will therefore increase the amount to be obtained in the market. To the extent that the regulated price of electricity from the nuclear assets is different from HOEP, a decrease in supply available from the regulated assets will change the RPP supply cost.

The upper right hand side of Figure 6 shows a similar situation for variances from expected demand. As with a change in supply, this affects RPP supply costs in two ways. An increase in demand produces an increase in the amount of supply that is required for the RPP consumers, and therefore a change in the amount that must be obtained and priced in the IESO-administered markets. A deviation in demand from forecast amounts also changes the supply and demand situation in the IESO-administered markets and affects prices.

Volatility in fuel prices also has a significant impact on market prices, and hence the RPP supply cost. This is shown in the lower left hand corner of Figure 6. The price of natural gas is by far the most volatile of the prices for the various fuels used to generate electricity in the IESO administered market. Natural gas fired generation typically sets the price during the hours of highest demand. It is during these hours that supply is the tightest, and vulnerability to a single fuel source is at its highest.

It is understood that these are not the only factors that influence the RPP supply cost. They do however account for the most significant portion of the risk. Taking into account additional sources of variance adds significant complexity to the modelling process and would only be expected to provide marginal value.

## Simulating the Model

A combination of statistical and econometric techniques was used to model this system and produce a distribution for the variance of RPP supply costs.

The basic methodology used was a Monte Carlo technique. Such techniques make a large number of simulations of a complex system where each of several input variables is subject to random factors that can be described by a probability distribution. The model simulates the system by taking a large number of random draws from the distributions of each of the variables subject to random factors. Each draw produces a value of the variable to be used as input to the model.

## Deriving Probability Distributions

The first steps were to estimate probability distributions for the three key factors: supply from nuclear assets, demand from Ontario consumers, and the volatility of natural gas prices.

To estimate nuclear supply probabilities, Navigant Consulting used available information and modeling assumptions about forced and unforced outage rates. Since Navigant Consulting's existing forecast of nuclear supply, and therefore of total Ontario supply, already models random forced outages, probabilities were chosen that represented extreme outage situations that are not captured in the ProSym model.

The major factor causing day-to-day variance in customer demand is weather. The most important weather factor is temperature. In the winter, colder weather means more electricity is used for space heating, and in the summer, warmer weather means more electricity is used for air conditioning. From historical weather data for 20 years, a historical frequency distribution of temperature was computed. This historical frequency distribution was then utilized as the (assumed normal) probability distribution of temperature.

To calculate the effect of weather on demand, data published by the IESO on the sensitivity of Ontario load to weather was used. These data show the effect of degree days on total Ontario load. The weather data provided a distribution of weather, and the translation through the IESO information provided a distribution of demand. The IESO data shows the effect of weather on load for the entire system. Electricity demand from eligible RPP consumers is likely to be more sensitive to weather than Ontario demand as a whole, because industrial load (which is not eligible for the RPP) is not very responsive to weather. In modeling the variance, 80% of the weather impact was therefore allocated in the winter to the RPP consumers; in summer, 60% was allocated. The difference in attribution reflects the fact that large commercial consumers which are not eligible for the RPP are very likely to have air conditioning, and therefore have load that is sensitive to increases in temperature, but are not very likely to have electric space heating.

Finally, a probability distribution for the volatility of natural gas prices was derived. The natural gas prices used to develop the parameters for the distribution were taken from historical Henry hub prices. Henry Hub has the most robust and complete historical data available (basis differential were used to convert these gas prices to Dawn Hub natural gas prices for forecasted values). Data from January 1990 through February 2009 was analyzed to develop the descriptive statistics.

The sensitivity of Ontario electricity prices to a change in natural gas prices was determined through simulation of the Ontario wholesale electricity production-cost model under both a high and low gas price scenarios.[25]

## The Supply / Demand Effect on Market Price

The diagram (Figure 6) and the above discussion indicate that a change in supply or demand conditions can be expected to have an impact on RPP supply cost in two ways: through the impact on the fraction of supply to be priced in the IESO-administered markets and through the price in those markets. The impact of the supply amount can be calculated directly. The impact on the market price must be estimated.

For that estimation, Navigant Consulting used econometric techniques. A single-equation regression model for the HOEP was constructed, with electricity demand and supply, and natural gas prices in Ontario as the independent variables. The resulting equation fit the data reasonably well. The coefficients of the independent variables were all highly significant and

[25] The results of the high / low gas price sensitivity are provided in the Navigant Consulting Ontario Wholesale Electricity Market Price Forecast Report.

had the expected signs. The equation explained about 60% of the historical variance in the HOEP.

## Computing RPP Supply Cost

All of these elements together then allowed calculation of the variance of the RPP supply cost from its expected level. For this calculation, as mentioned, a random simulation (Monte Carlo) technique was used, under which independent draws from each of the three probability distributions were made.

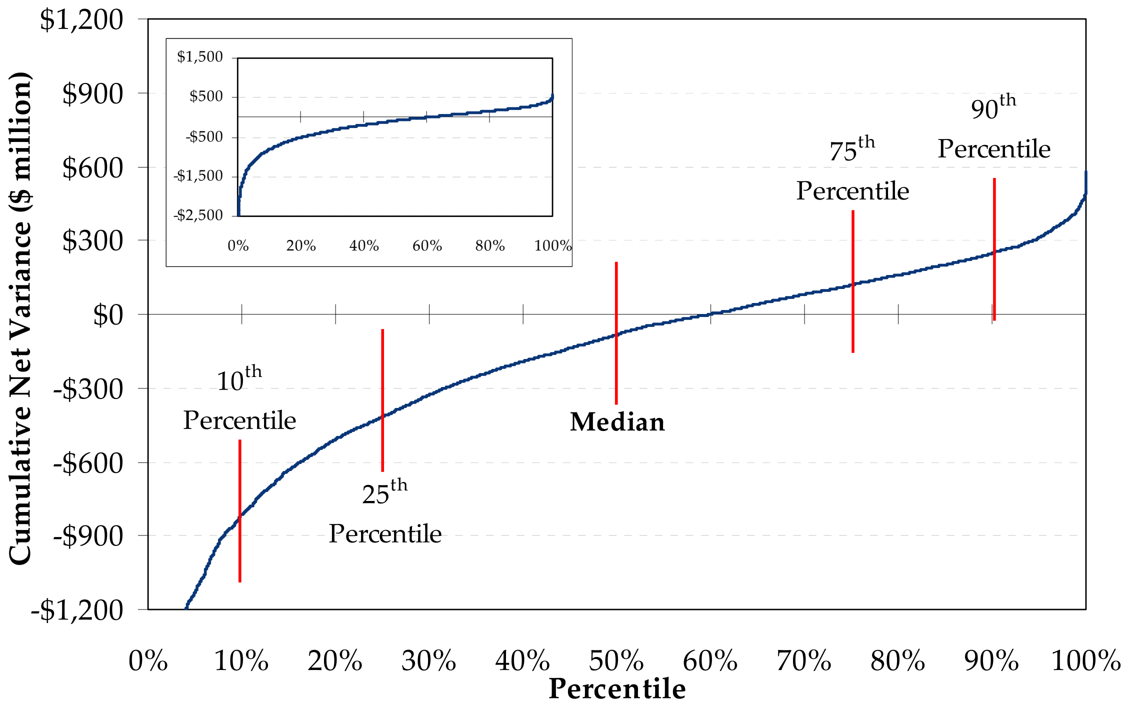
Each set of random draws sampled from the three probability distributions was used to obtain values of supply from the nuclear assets, weather conditions, and natural gas prices. Weather conditions were translated into demand impacts, using the information from the IESO. The supply and demand conditions were then translated into a market price, using the structure of the estimated equation. Natural gas price conditions were translated into a market price using the sensitivity terms obtained from the static price forecast.

The variance of the RPP supply cost was then calculated by comparing the RPP supply cost calculated using the static forecast values to the values calculated from the conditions under each of the random draws.

## Variance Results

Figure 7 shows the cumulative variance over the entire year for all 5000 simulations. The majority of simulations (roughly 3000 of the 5000) have negative variances; that is, they generate variances that consumers will later have to pay. Also shown on this chart are the approximate locations of the variance simulations chosen to represent the 10th, 25th, 50th, 75th, and 90th percentiles.

**Figure 7: Cumulative Variances over Entire Term**




Source: Navigant Consulting

The median variance, which represents the adjustment that will be applied to the RPA, was found to be negative $61 million. The inclusion of this adjustment factor in the total RPP supply cost means that there is an equal likelihood of either a consumer credit variance or a consumer debit variance at the end of the RPP year. This adjustment factor is referred to as the stochastic adjustment in the body of this report.