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Ontario

Regulated Price Plan

Price Report

May 1, 2006 to April 30, 2007

Ontario Energy Board

April 12, 2006

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, 2006 through April 30, 2007. The prices were developed using the methodology described in the Regulated Price Plan Manual (RPP Manual). The RPP Manual was developed within the context of a larger regulatory proceeding on the RPP involving significant stakeholder input and consultation.

The principles that have guided the Ontario Energy Board (OEB or the Board) in developing the RPP were established by the Ontario Government. 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. Under existing legislation RPP prices will be reviewed by the OEB and may be reset every 6 months.

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, 2006, 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 by the government, or that are subject to a revenue limit;
- the costs related to the contracts signed by non-utility generators (NUGs) with the former Ontario Hydro; and
- the costs of the supply contracts and the level of the variance account carried by the Ontario Power Authority (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 load 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 hourly Ontario energy price (HOEP).

Average RPP Supply Cost

The hourly market price forecast for this computation was developed by Navigant Consulting, Inc. (Navigant Consulting or NCI). The forecast of the simple average HOEP for 12 months from May 1, 2006 is $62.30 / MWh (6.230 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 $67.65 / MWh (6.765 cents per kWh). This represents the load-weighted average electricity price that RPP consumers would pay if all their electricity supply was purchased out of the Ontario wholesale electricity spot market.

The other components of the RPP supply cost are expected to temper this price. The collective impact of the other components is summarized by two factors, the Global Adjustment (or Provincial Benefit) and the OPG Non-prescribed asset (ONPA) rebate (or OPG Rebate).

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 are below market prices, and the cost of supply contracts held by the Ontario Power Authority (OPA), most of which are above market prices. The forecast net impact of the Global Adjustment is to reduce the average RPP supply cost by $4.79 / MWh (0.479 cents per kWh).

The OPG Rebate (or ONPA Rebate) reflects the revenue limit applied to OPG's coal-fired generating facilities and the remaining non-prescribed hydroelectric facilities. These facilities are limited to $46 / MWh.[1] The forecast net impact of the OPG Rebate is to reduce the average RPP supply cost by $6.45 / MWh (0.645 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 $1.11 / MWh (0.111 cents per kWh). Without this adjustment, the RPP would be expected to end the year with a small consumer debit variance.

An additional adjustment factor is required to recover the expected balance in the OPA variance account as of April 30, 2006. The majority of the current outstanding balance accumulated as a result of higher than forecast electricity prices during the previous summer. The forecast adjustment factor to recover the existing variance balance is $5.04 / MWh (0.504 cents per kWh).

The resulting average RPP supply cost, or the RPA, is $62.56 / MWh (6.256 cents per kWh). This is summarized in Table ES-1.

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1 A small percentage of this output that is expected to be sold through the OPA forward contract pilot auction program is limited to $51 / MWh as opposed to $46 / MWh.

Table ES-1: Average RPP Supply Cost Summary (for the 12 months from May 1, 2006)

RPP Supply Cost Summary for the period from May 1, 2006 through April 30, 2007			
Forecast Wholesale Electricity Price	$62.30		
Load-Weighted Price for RPP Consumers ($ / MWh)			$67.65
Impact of the Global Adjusment ($ / MWh)		+	-4.79
Impact of the OPG Non-prescribed Asset Rebate ($ / MWh)		+	-6.45
Adjusment to Address Bias Towards Unfavourable Variance ($ / MWh)		+	1.11
Adjusment to Recover Existing Variance ($ / MWh)		+	5.04
Average Supply Cost for RPP Consumers ($ / MWh)		=	**$62.56**

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 price the following RPP term.

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 and one for consumers with eligible time-of-use meters who pay time-of-use (TOU) prices.

Conventional Meter Regulated Price Plan

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 will change 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:

- $RPCMT_1$ = **5.8** cents per kWh, and.
- $RPCMT_2$ = **6.7** cents per kWh.

The average price for conventional meter RPP consumption is forecast to be equal to the RPA. The tier thresholds are set such that there is roughly a 50/50 split of forecast consumption at the lower tier price and at the higher tier price, resulting in tier prices that are distributed symmetrically around the RPA.

Smart Meter Regulated Price Plan

Consumers with eligible time-of-use (or "smart") meters that can determine when electricity is consumed during the day will pay under a time-of-use (TOU) price structure. The prices for this plan are based on three time-of-use periods per day. 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. These three prices are related to each other in approximately a 1:2:3 ratio.

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

- $RPEM_{OFF}$ = **3.5** cents per kWh,
- $RPEM_{MID}$ = **7.5** cents per kWh, and
- $RPEM_{ON}$ = **10.5** cents per kWh.

The off-peak time-of-use price applies for more than 50% of the hours in a week. The on-peak period time-of-use price applies for 15% of the hours in a summer week and, because the on-peak period changes in the winter, applies for just over 20% of the hours in a winter week. The mid-peak price applies during the remaining hours; that is, 35% of the hours in a summer week and 30% of the hours in a winter week. The hours for each of these three TOU periods are set out in the RPP Manual. The average price for smart meter RPP consumption, weighted by forecast consumption in each of the time-of-use periods, is also forecast to be equal to the RPA.

OEB Role in Determining Prices under the RPP

The OEB has a different role in calculating the commodity electricity prices that RPP consumers will pay relative to its role in regulating the distribution rates that utilities collect for delivering electricity to homes and businesses.

Distribution utilities file applications with the Board for approval of cost-based charges levied on consumers for providing distribution services. The OEB scrutinizes these applications and sets reasonable rates to recover justifiable and prudent costs from consumers.

In contrast, for the RPP, the OEB forecasts the total cost of supplying the electricity used by RPP consumers and converts that cost into stable and predictable prices for RPP consumers. The forecast cost of supply is based on a set of prices that, unlike distribution rates, are not determined by the OEB. Some of these prices will be determined in the open market and will fluctuate hourly based on supply and demand. Some of these prices are determined by Government regulation or are based on contracts entered into by the OPA or the former Ontario Hydro. Simply stated, the OEB does not regulate the electricity commodity prices which form the basis of the electricity prices in this RPP Price Report. In other words, while the OEB determines the electricity commodity prices that RPP consumers will pay, the OEB does not determine the various commodity prices that are blended together to set the RPP prices.

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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) was mandated to develop a regulated price plan (RPP) for electricity prices to be charged to consumers that have been designated by regulation. The first prices were implemented under the RPP effective on April 1, 2005, as set out in regulation by the Ontario Government. This report, and the prices contained herein are intended to be in effect on May 1, 2006 and remain in effect until April 30, 2007 barring any required true-up or rebasing.[2]

The Board has prepared a Regulated Price Plan Manual (RPP Manual) to explain how the RPP price is set. It was prepared within the context of a larger regulatory proceeding (designated as RP-2004-0205) in which interested parties assisted the Board in developing the elements of the RPP.

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, 2006.

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 Report (Market Price Forecast Report),[3] prepared by Navigant Consulting Inc. (Navigant Consulting or NCI), contains the Ontario wholesale electricity market price forecast. The document details

[2] In accordance with the RPP Manual, price resetting is expected to be considered for implementation every six months. The price resetting will determine how much of a price change will be needed to recover both the forecast RPP supply cost and the accumulated variance in the OPA variance account over the next 12 months. In addition to the six month reconsideration, the RPP Manual allows for an automatic "trigger" based adjustment if the unexpected variance exceeds $160 million.

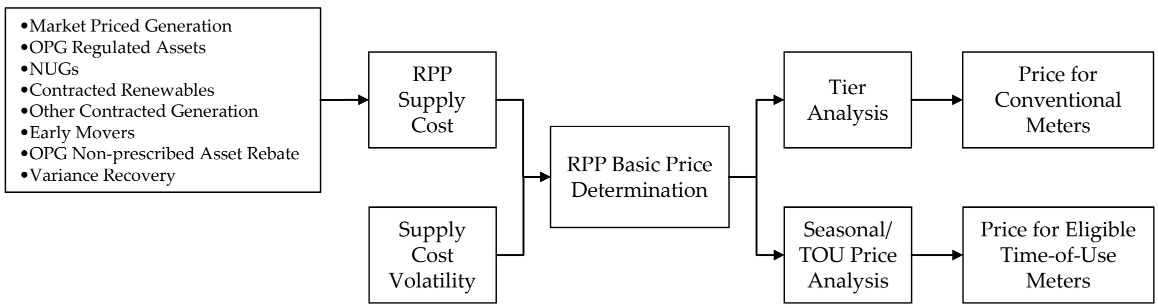
[3] The Market Price Forecast Report is posted on the OEB web site, along with the RPP Price Report, on the RPP web page.

all of the 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 cost variance (carried by the Ontario Power Authority or 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 assumption source 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 RPP supply cost;
- M is the amount that the RPP supply would have cost under the Market Rules;
- α is the RPP proportion of the total demand in Ontario;[4]
- A is the amount paid to prescribed (or regulated) generators;[5]
- B is the amount those generators would have received under the Market Rules;
- C is the amount paid to non-utility generators (NUGs) under existing contracts;
- D is the amount those NUGs would have received under the Market Rules for 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;

4 The expression in square brackets is the Global Adjustment; it is applied to the RPP according the load ratio share represented by RPP consumers, denoted here as α.

5 These are generators designated by regulation and whose output is subject (in whole or in part) to a regulated rate which is currently set by Government regulation. It is envisioned that this regulated rate will be set by the Board in the future.

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

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

The OPG Non-prescribed Asset (ONPA) Rebate (or OPG Rebate) is not included in Equation 1 because it did not exist at the time the RPP Manual was developed. The OPG Rebate is however addressed in Section 2.2.8 of this report and is considered as an after-the-fact adjustment to the total RPP Supply 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 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 OPG Rebate and a forecast of the stochastic adjustment, which are not included in Equation 1. As mentioned previously, the OPG Rebate is not included in Equation 1 because it did not exist at the time the RPP Manual was developed. The stochastic adjustment is included in the RPP Manual, however, as an additional cost factor calculated outside of Equation 1.

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:

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

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

- The forecast of hourly Ontario electricity price (HOEP) on the IESO-administered market in each hour of the year; and

- The forecast of demand from RPP consumers in each hour of the year.

The forecast of HOEP is taken directly from the Ontario Market Price Forecast Report. The Ontario Market Price Forecast Report also contains a detailed explanation of the assumptions that underpin the forecast. 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).

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

Term	Quarter	Calendar Period	On-peak	Off-peak	Average	Term Average
RPP Year	Q1	May 06 - Jul 06	$84.35	$36.42	$59.24	
	Q2	Aug 06 - Oct 06	$88.44	$37.37	$61.69	
	Q3	Nov 06 - Jan 07	$100.99	$39.92	$69.00	
	Q4	Feb 07 - Apr 07	$80.24	$40.19	$59.26	$62.30

Source: Navigant Consulting 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 forecast of the hourly electricity demand from RPP consumers comes from forecasts of the fraction of their total load consumed in each hour (their load shape) and the fraction that they represent of the total system-wide load for all consumers in Ontario.

No precise load shape is available that is specific to only RPP consumers. The approximation widely used is called the Net System Load Shape, or NSLS. Each distributor's NSLS is its total load shape (which is known because the distributor has and is billed on an interval meter) minus the load of consumers with interval meters whose hourly usage is recorded. At present, almost all the consumers with interval meters are large commercial or industrial consumers, who are not eligible for the RPP. The NSLS is therefore a good approximation of the load shape of consumers who are eligible for RPP.

A historical system-wide NSLS was therefore used as a forecast of the load shape of RPP consumers. The system-wide NSLS was developed from a representative sample of net system load shapes from distributors across the province. The sample of distributors encompasses a broad spectrum of distributor size and location. The same load shape was used to set the RPP prices for the previous RPP year, and has proven to be a reliable estimate. Load shapes change only very slowly, so this is a reasonable approximation..[6]

Figure 2 presents a chart of the forecast average hourly weekday NSLS and HOEP for January. This chart clearly demonstrates that NSLS consumption is higher during those times of day when prices are forecast to be higher. HOEP is based on, among other things, total system

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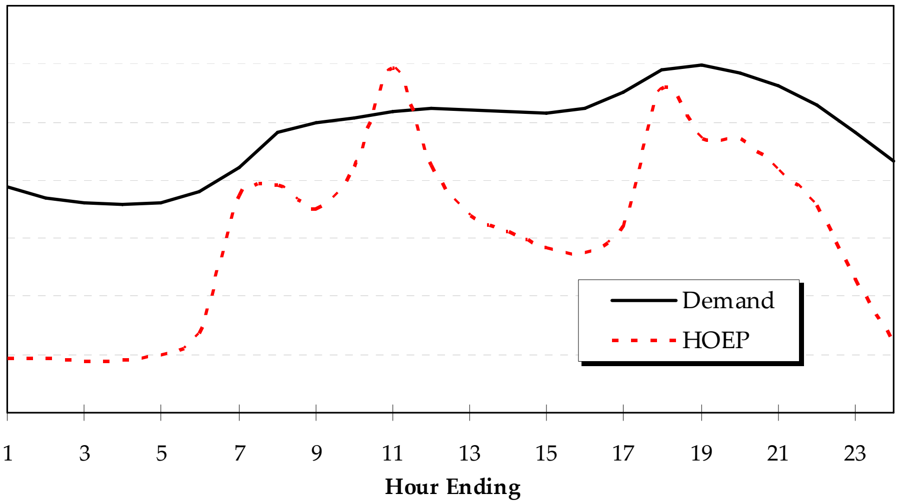
[6] The NSLS can be expected to change more quickly as more "smart" meters are installed.

demand; hence there are factors outside NSLS consumption that impact the price in each hour of the day.

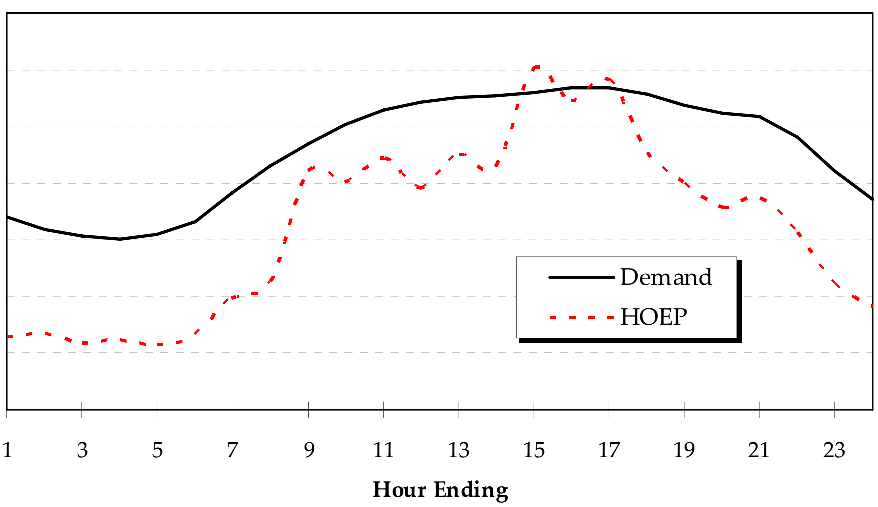
Figure 2: Average Hourly NSLS Consumption and Forecast HOEP for January



Source: NCI
Note: All times are EST

Figure 3 presents the same information for July. Again, this chart clearly demonstrates that NSLS consumption is higher during times when prices are forecast to be higher.

Figure 3: Average Hourly NSLS Consumption and Forecast HOEP for July



Source: NCI
Note: All times are EST

A similar pattern is observed in the monthly NSLS consumption pattern. NSLS consumption is higher during those months when prices are forecast to be higher

The forecast of the market-based component of the RPP supply cost is therefore the demand of RPP consumers times the HOEP at the time of consumption. As shown in Table 1 on page 5, the forecast simple average HOEP for the period May 1, 2006 to April 30, 2007, is $62.30 / MWh (6.230 cents per kWh). Based on the forecast RPP consumption pattern the load weighted average price for RPP consumers is $67.65 / MWh (6.765 cents per kWh).

The amount of electricity supplied under the RPP depends on which consumers are eligible to receive the RPP. Under Government regulation, the current eligibility criteria are to be maintained through March 31, 2008. Based on these criteria, eligible consumers are all residential and small commercial consumers and designated consumers in the municipalities, universities, schools and hospitals (MUSH) sector as well as farms.

RPP Attrition

Over the course of the first RPP year some consumers chose to leave the RPP program to sign competitive retail supply contracts. Some RPP customers with interval meters may also have chosen to purchase power in the spot market instead of under the RPP. The effect of this migration away from the RPP (or attrition) is not expected to have a pronounced impact on: a) the load shape of RPP consumers, and b) the total volume of RPP consumers for the period under consideration. Some consumers have also returned to the RPP from retail contracts.

With respect to the load shape, the most significant risk would be commercial customers with relatively "flatter" load shapes or consumption patterns leaving the RPP, which would result in a "peakier" load shape for the remaining RPP consumers. This "peakier" load shape would then result in higher than forecast overall market price for the remaining RPP consumers. However, there is no evidence to date that the RPP load shape has experienced a material change.

With respect to the total volume of RPP consumers, all of the factors contributing to the average RPP supply cost are expressed in $ / MWh (or cents per kWh). Hence, if the volume changed significantly through attrition but all other factors (such as load shape, fuel prices, and generator availability) remain unchanged, the average RPP supply cost would not change.

RPP attrition is a potential risk factor in determining the RPP supply cost and will continue to be tracked closely.

These eligibility criteria result in approximately 49.5% or just under half of the total electricity withdrawn in the province being eligible for and taking power under the current RPP. This forecast maintains that ratio; 49.5% of the total electricity withdrawn in Ontario is eligible to receive power under the RPP.

The value of $\boldsymbol{\alpha}$ is therefore 0.495.

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 hourly generation multiplied by the Ontario market prices during those hours. Forecasts of both of these variables were taken from the production cost model. For details the production cost model and the wholesale market price forecast, see the Navigant Consulting Market Price Forecast Report.

The amount paid to the prescribed generators (quantity A in Equation 1) is determined by Government regulation. Government regulation stipulates that the price for the prescribed hydroelectric assets will be \$33 / MWh for up to 1,900 MW in any hour, while the price for the prescribed nuclear assets will be \$49.50 / MWh.[7]

Quantity B was therefore forecast by multiplying these fixed prices per MWh for the prescribed generators 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 energy price. These quantities are available from the production cost model as an aggregate for the NUGs as a whole.

The amount that the NUGs receive under their contracts with Ontario Electricity Financial Corporation (OEFC – the agency responsible for administering the NUG contracts), quantity C in Equation 1, is not publicly available information, although it is known that most of the contracts provide for on-peak and off-peak prices. The Board has obtained from the OEFC a forecast of the prices for these generators on a monthly basis. This forecast was used to compute an estimate of the total payments to the NUGs under their contracts, or amount C in Equation 1.

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7 The 1,900 MW hourly threshold applies to the total output from all of the prescribed hydroelectric assets.

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 contracted under the recent Renewable Energy Supply (RES) Request for Proposals (RFP).

The size, generation type, and location of the successful RES projects have been announced by the Ministry of Energy (MoE). The production cost model produced forecasts of their hourly output, using the specification of the generators as they appear in the Market Price Forecast Report. Quantity F in Equation 1 is therefore the forecast hourly output of the renewable generation multiplied by the forecast HOEP 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 MoE has released the weighted average price for both Renewable RFP I and Renewable RFP II, they are $79.97 / MWh and $86.40 / MWh respectively.

The cost of contracts awarded under the standard offer program are not likely to have a material impact on the total RPP supply cost in this RPP year and hence are not included in the calculation. In subsequent years however the cost of the standard offer contracts will be considered as part of this adjustment term.

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 whose generation from its Bruce A nuclear facility is under an output-based contract.

The contribution of conventional generation under contract to the OPA to quantity G relates to the Clean Energy Supply (CES) RFP and the "early mover" contracts.[8] In addition to the conventional generation contracts awarded under the CES RFP process, a 10 MW demand response contract was awarded to Loblaws. The cost of this project to consumers will be calculated in the same manner as the other CES contracts.

The costs of the early mover and the CES contracts are based on an estimate of the contingent support payments to be paid out 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 average NRR for the CES contracts was announced by the MoE to be $7,900 per megawatt-month.[9]

The cost to the OPA of any demand response (DR) or demand side management (DSM) contracts, above and beyond the Loblaws 10 MW program, awarded in the future would also be captured in term G of Equation 1.

The Bruce Power contract stipulates that output from the Bruce A facility be paid $57.37 / MWh, indexed to inflation, plus fuel costs. At today's fuel prices, this amounts to $63 / 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 Province 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. Adjustments for inflation are made on an annual basis.

2.2.6 Estimate of the Global Adjustment (or Provincial Benefit)

The overall impact of the central term in Equation 1 – $\alpha\ [(A - B) + (C - D) + (E - F) + G]$ – is forecast to reduce the RPP unit cost by $4.79 / MWh (0.479 cents per kWh). This essentially represents the forecast of the average Global Adjustment that would accrue to RPP consumers over the period from May 1, 2006 to April 30, 2007.

The contract awarded to OPG's Lennox GS regarding reliability must-run (RMR) status is not between OPG and the OPA, but between OPG and the Independent Electricity System Operator (IESO). Hence, the cost of the contract is not recovered through the global adjustment and is

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8 Two facilities holding CES contracts are expected to be operational during this RPP period; the GTAA Cogeneration Facility and the Loblaws Demand Response Program. Five facilities signed early mover contracts with the OPA, they include; the Brighton Beach facility, the TransAlta Sarnia facility, and three Toromont facilities.

9 Given the ministerial directive to the OPA, the NRR for the early movers was assumed to be the same.

not included in the RPP supply cost. The cost will instead be recovered through the hourly uplift charge.[10]

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 06 – Apr 07). The second represents the price adjustment required to recover 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 consumer debit variances in some months are generally offset by interest income the OPA receives from carrying consumer 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, as it represents the price adjustment necessary to recover the total net variance incurred over the first RPP term (Apr 05 – Apr 06) plus any accumulated interest over the upcoming RPP period. As of February 28, 2006 the net variance account balance was an unfavourable or negative $377 million including interest.

The net variance account balance as of April 30, 2006 is forecast to remain unchanged from this level. Essentially, the factors that would otherwise contribute to a more unfavourable (more negative) net variance are expected to be offset by a factor that would otherwise contribute to a less unfavourable (less negative) net variance.

The factors contributing to a more unfavourable net variance include accumulated interest on the gross variance balance, costs associated with the Early Movers and Bruce contracts which are recovered through the Global Adjustment and higher forward natural gas prices for April (relative to those in the forecast used to set the current RPP price). The net impact of these factors is expected to be offset by wholesale electricity prices in March that were below those in the forecast used to set the current RPP price.

The overall impact of this term increases the average RPP supply cost by $5.04 / MWh (0.504 cents per kWh).

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10 The hourly uplift charge includes wholesale electricity market services which, in part, are provided by the IESO to ensure reliability of the system. RPP consumers do not see this charge on the simplified bill. For RPP consumers, this means that the costs associated with OPG's Lennox facility will ultimately be recovered through the Regulatory charge on consumer bills. This charge includes the hourly uplift charge.

2.2.8 Cost Adjustment Term for OPG Non-Prescribed Asset Rebate (or OPG Rebate)

On February 23, 2005 the Ontario Government announced a partial revenue limit on the non-prescribed assets (i.e., non-baseload hydroelectric and coal generation facilities) owned by OPG. The regulation limited a portion of the revenues from OPG's non-prescribed facilities to $47 / MWh for a 13 month period ending April 30, 2005. An estimate of the rebate paid to consumers resulting from this revenue limit was included in the initial RPP price implemented on April 1, 2005. The rebate is called either the OPG Non-Prescribed Asset (ONPA) Rebate, or the OPG Rebate.

On February 9, 2006, the Ontario Government announced that the partial revenue limit had been extended through April 2009. However, some of the terms have been revised.

- The revenue limit for the period covered by this report is $46 / MWh, down from $47 / MWh.
- In addition, the rebate will be paid out on a quarterly basis as opposed to at the end of the term.

The OPG Rebate is also affected by the volumes sold through the OPA administered forward contract Pilot Auction (PA) program. Volumes sold by OPG through the PA, which are from the ONPA assets, are subject to a revenue limit of $51 / MWh as opposed to $46 / MWh. The rebate contribution from the volumes sold through the PA is calculated as the difference between the auction selling price and the cap price of $51 / MWh.

With this rebate included in the calculation of the RPP supply cost, as required by Government regulation, there is a further $6.45 / MWh (0.645 cents per kWh) forecast reduction in the average RPP supply cost.[11] This term is not included in Equation 1, but is considered part of the total RPP supply cost.

2.3 Correcting for the Bias Towards Unfavorable Variances

All of 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, since nuclear generation plants tend to operate at about an 80% capacity factor, these facilities are more likely to "under-generate" (due to unscheduled outages) than to "over-generate" (i.e., there is 20% upside versus 80% 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

[11] Included in this term is an estimate of the interest cost to be incurred by the OPA as a result of the quarterly payment structure.

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 and OPG Rebate components 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 as 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 $1.11 / MWh (0.111 cents per kWh). This amount should be collected from RPP consumers to ensure that the "expected" variance at the end of the RPP year is zero.

2.4 Total RPP Supply Cost

With these additional factors (OPG Rebate and stochastic adjustment) taken into consideration, the total RPP supply cost is estimated to be approximately $4.76 billion.[12] Figure 4 breaks this supply cost into the five major cost streams. "Market-based generation" includes a small amount of output from OPG that is not subject to either the regulated price or the revenue limit based on the provisions of the regulations governing these mechanisms.

Figures 4 and 5 below illustrate different concepts. Figure 4 shows the expected breakdown of the RPP's *total cost*; Figure 5 differs in that it shows the expected proportions of *physical electricity* (i.e., kilowatt-hours) supplied to RPP consumers by each of the four generation categories. For example, while OPG prescribed (or regulated) generation is expected to contribute 30% of the total RPP supply cost, these facilities are expected to supply a much higher proportion – approximately 41% – of the total electricity used by RPP consumers.

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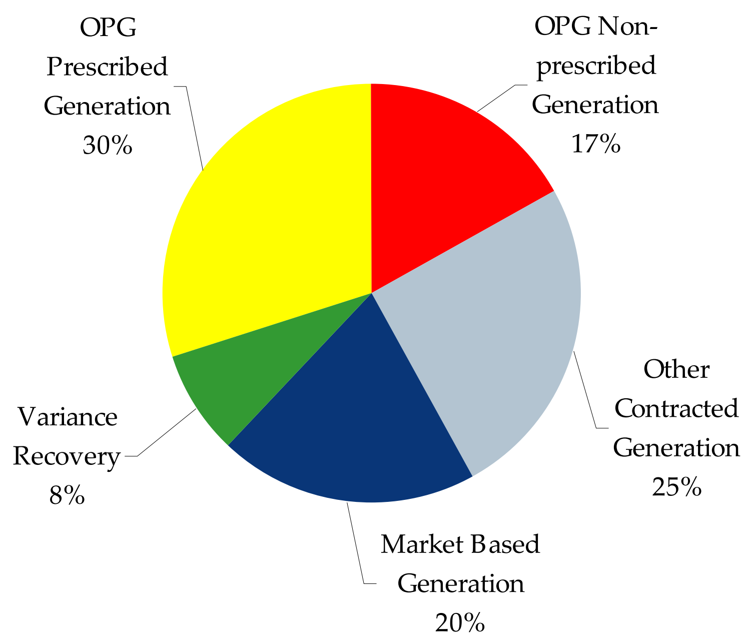
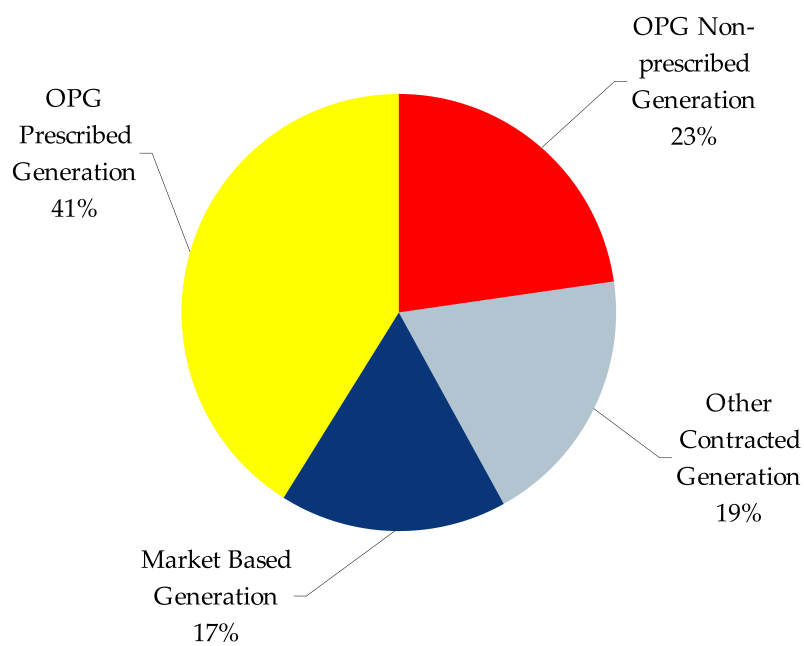
[12] The total cost figure includes the cost allocated toward the recovery of the existing variance account balance.

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



Source: NCI

Figure 5: Components of RPP Supply (% of kWh)



Source: NCI

The following table itemizes the various steps discussed above to arrive at the average RPP supply cost of $62.56 / MWh. This average supply cost corresponds to an average RPP price, which is referred to as RPA, of 6.256 cents per kWh.

Table 2: Average RPP Supply Cost Summary

RPP Supply Cost Summary			
for the period from May 1, 2006 through April 30, 2007			
Forecast Wholesale Electricity Price	$62.30		
Load-Weighted Price for RPP Consumers ($ / MWh)			$67.65
Impact of the Global Adjusment ($ / MWh)		+	-4.79
Impact of the OPG Non-prescribed Asset Rebate ($ / MWh)		+	-6.45
Adjusment to Address Bias Towards Unfavourable Variance ($ / MWh)		+	1.11
Adjusment to Recover Existing Variance ($ / MWh)		+	5.04
Average Supply Cost for RPP Consumers ($ / MWh)		=	**$62.56**

Source: NCI

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 supply price, RPA. This chapter will detail the determination of the prices for the tiers, $RPCM_{T1}$ and $RPCM_{T2}$, and the determination of the prices for consumers with eligible time-of-use (TOU) meters who are being charged 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 RPP consumers with conventional meters. For such consumers, there is a tiered pricing structure with two price tiers — $RPCM_{T1}$ (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 such that the average revenue generated is equal to the RPA. This is achieved by maintaining the existing ratio between the upper and lower tier prices (in other words, the existing ratio of 5.0 and 5.8 cents per kWh) and forecasting consumption above and below the threshold in each month of the RPP.

The resulting **tier prices** are:

- $RPCM_{T1}$ = **5.8** cents per kWh, and.
- $RPCM_{T2}$ = **6.7** 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.[13] 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 will apply will vary 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, adjusted by the global adjustment,

13 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 meters consumers is from the NSLS of the conventional meter consumers.

the variance recovery factor and the OPG Rebate. The mid-peak price, $RPEM_{MID}$, was similarly set. Once these two prices are set, and given the forecast levels of consumption during each of the three periods, the on-peak price, $RPEM_{ON}$, is determined by the need to make the load-weighted average price equal to the RPA. 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:

- $RPEM_{OFF}$ = **3.5** cents per kWh
- $RPEM_{MID}$ = **7.5** cents per kWh, and
- $RPEM_{ON}$ = **10.5** 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*: 10 p.m. to midnight and midnight to 7 a.m.
  - *Winter and summer weekends and holidays*:[14] 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. and 8 p.m. to 10 p.m.
  - *Summer weekdays (May 1 to October 31)*: 7 a.m. to 11 a.m. and 5 p.m. to 10 p.m.
- *On-peak* period (priced at $RPEM_{ON}$)
  - *Winter weekdays*: 7 a.m. to 11 a.m. and 5 p.m. to 8 p.m.
  - *Summer weekdays*: 11 a.m. to 5 p.m.

The above times are given in local time (i.e., the times given reflect daylight savings time in the summer).

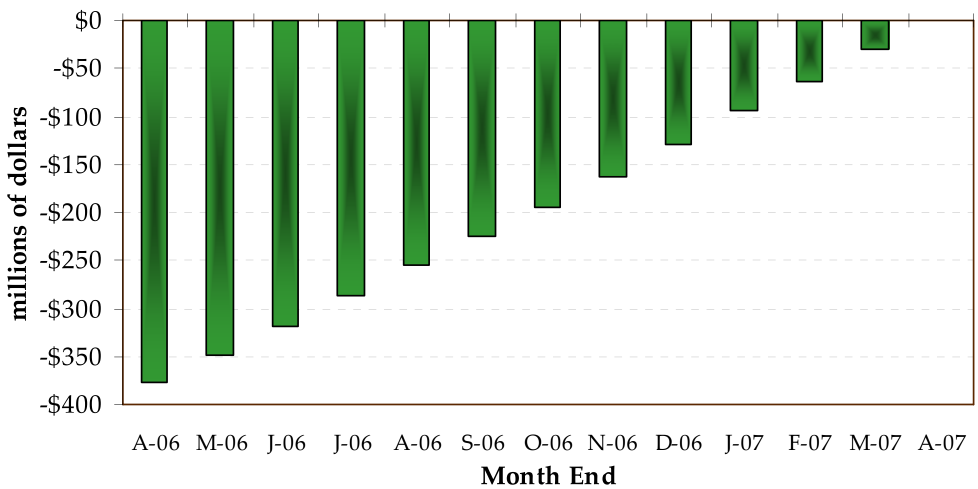
[14] For the purpose of RPP time-of-use pricing, a "holiday" includes the following days: New Year's Day, Good Friday, Christmas Day, Boxing Day, Victoria Day, Canada Day, Labour Day, Thanksgiving Day, and the Civic Holiday. When any holiday falls on a weekend (Saturday or Sunday), the next weekday following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

4. Expected Variance

Once the RPP prices are set, the monthly expected variance can be calculated directly. The expected variances are published here because they are the variances against which the unexpected variances will be tracked. The variances incurred during the upcoming RPP period are addressed separately from the recovery of the variance carried over from the previous RPP period.

The additional variance recovery factor included in the RPP supply cost is determined such that the existing variance when prices are reset on May 1st, 2006 is reduced to zero over the following 12 months as depicted in Figure 6.

Figure 6: Forecast Increase of Existing Variance Account Balance ($ million)



Source: NCI

4.1 Monthly Variances

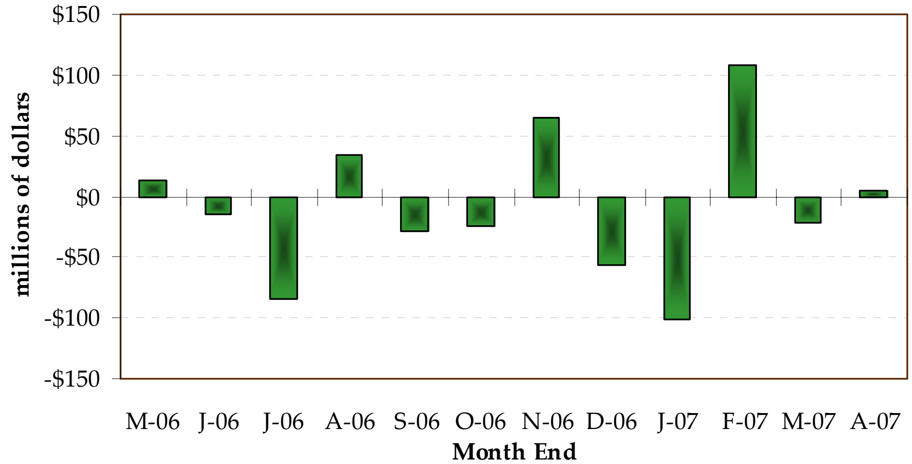
The monthly expected variance is the difference between the monthly expected RPP supply cost and the monthly amount expected to be collected from RPP consumers taking supply under the RPP during the current RPP period.

The monthly RPP supply cost depends on all of the terms in Equation 1. It was calculated as part of the calculation of the total RPP supply cost, which was taken as the sum of the monthly calculations for each of the terms in Equation 1.

The monthly revenue from consumers taking supply under the RPP is simply their demand below and above the tier threshold times the lower and higher tier prices. These demand levels were estimated during the calculation of the tier prices.

The expected variance can therefore be readily calculated. This is shown in Figure 7. Figure 7 and Figure 8 assume that the rebate from the revenue cap on OPG's non-prescribed assets is paid out on a quarterly basis with a one month lag. Consumer credit variances are positive in these charts.

Figure 7: Expected Monthly Variance

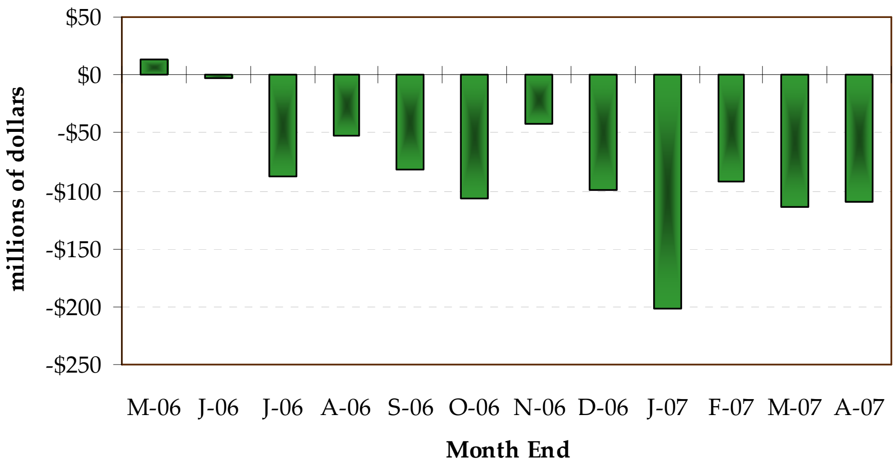


Source: NCI

The RPP price was set so that the cumulative expected variance over the year is zero (i.e. the RPP prices recover all of the cost over the year). Figure 8 below shows the cumulative expected variance for each month of the RPP year. The result of the one month lag in the payment of the OPG non-prescribed asset rebate is that the cumulative expected variance at the end of the RPP year is not equal to zero. The cumulative total remains negative by the expected value of the final payment owing from OPG, which is assumed to be received in the first month of the next RPP term (beginning May 1, 2007).[15]

15 The computed cumulative variance does not total zero because of two factors: (1) rounding error resulting from setting the tier prices to only a tenth of a cent, and (2) the payment of the OPG Rebate is not instantaneous and a one-month lag is expected. The expected variances reported here are corrected for the rounding error. The cumulative variance at the end of the year remains not equal to zero, and is, instead, equal to the forecast final OPG Rebate payment.

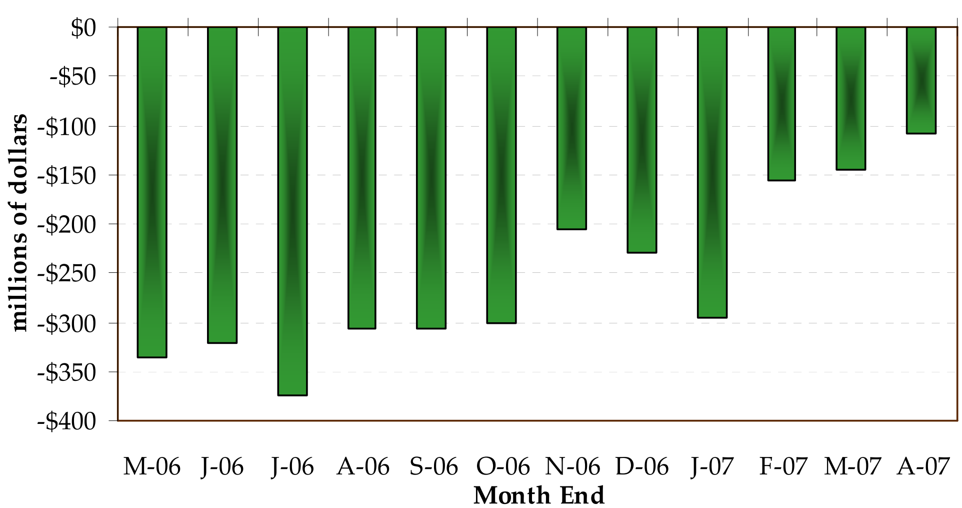
Figure 8: Cumulative Expected Monthly Variance ($ million)



Source: NCI
Note: The remaining balance at the end of the RPP Year (Apr 07) is equal to the outstanding value of the quarterly OPG Rebate. It is forecast to be reduced to zero the following month when payment is received by the OPA.

The combined effect of the recovery of the existing variance and the expected monthly variances accumulated over the RPP term is shown in Figure 9. The values in each month of Figure 9 represent the total expected balance in the OPA variance account at the end of each month.

Figure 9: Expected Monthly Variance Account Balance ($ million)



Source: NCI
Note: The remaining balance at the end of the RPP Year (Apr 07) is equal to the outstanding value of the quarterly OPG Rebate. It is forecast to be reduced to zero the following month when payment is received.

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 four sources: those under contract, those that are regulated, those that are subject to a revenue limit, and those priced in the IESO-administered market. Sources subject to regulation are the supply from the regulated OPG assets (baseload hydroelectric and nuclear). Sources under contract include supply from existing non-utility generators (NUGs) that are under contracts now held by the Ontario Electricity Financial Corporation (OEFC); and from any contracts, such as the results of the current RFPs, which are between the suppliers and the OPA. Sources subject to a revenue limit are the supply from OPG's non-prescribed assets (coal and non-regulated hydroelectric).

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.[16]

The interaction among these factors can be complex, because the first two, supply and demand conditions, can affect the third, the Ontario 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.

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.

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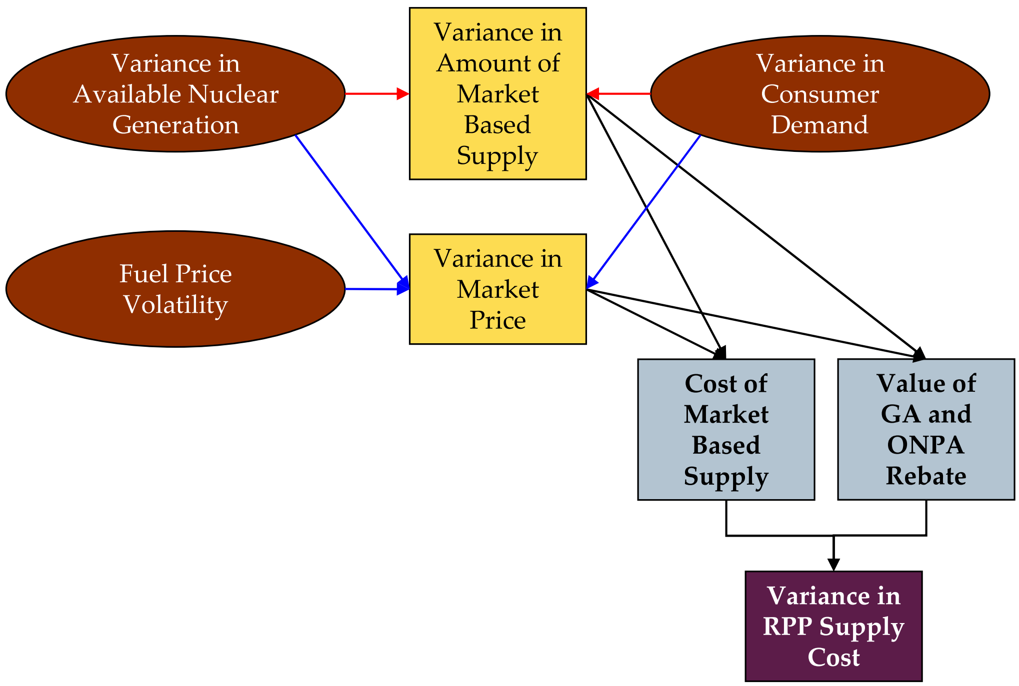
16 Variations in fuel prices, such as natural gas and coal, can have a significant influence on the Ontario market price and hence the RPP supply cost.

The Model of Supply Cost Variance

Figure 10 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 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 10: Diagram of Supply Cost Variance



Source: NCI

The factor in the upper left of Figure 10 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 Ontario in turn affects the market price in Ontario, 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 (hourly Ontario energy 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 OPG's 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 OPG's nuclear assets will therefore increase the amount to be obtained in the market. Since the regulated price of electricity from OPG's nuclear assets is expected, at most times, to be lower than HOEP, a decrease in supply available from the regulated assets will increase the RPP supply cost. This is not necessarily the case for variations in the amount of supply from Bruce Power's nuclear assets. The contract price for output from Bruce A is higher than the regulated rate for OPG, hence there may be periods when supply receiving market prices is less expensive than supply from Bruce.

The upper right hand side of Figure 10 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 10. 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. While coal-fired generation in Ontario is currently the predominant marginal resource, 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 heat, but are not very likely to have electric space heating.

Finally, a probability distribution for the volatility of natural gas prices was derived. A "random walk with mean reversion" technique was used to determine the variance or volatility of natural gas prices. The fundamental concept of the "random walk with mean reversion" approach is that it reflects a variance parameter that seeks to incorporate the fundamentals of randomly occurring outcomes while staying within the framework of observable pricing behaviour that is consistent with energy and other commodity market pricing behaviour. 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 September 2005 was analyzed to develop the descriptive statistics.

The sensitivity of Ontario electricity prices to a change in natural gas price was determined through simulation of the Ontario wholesale electricity production-cost model under both a high and low gas price scenarios.[17]

The Supply/Demand Effect on Market Price

The diagram 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 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 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 11 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

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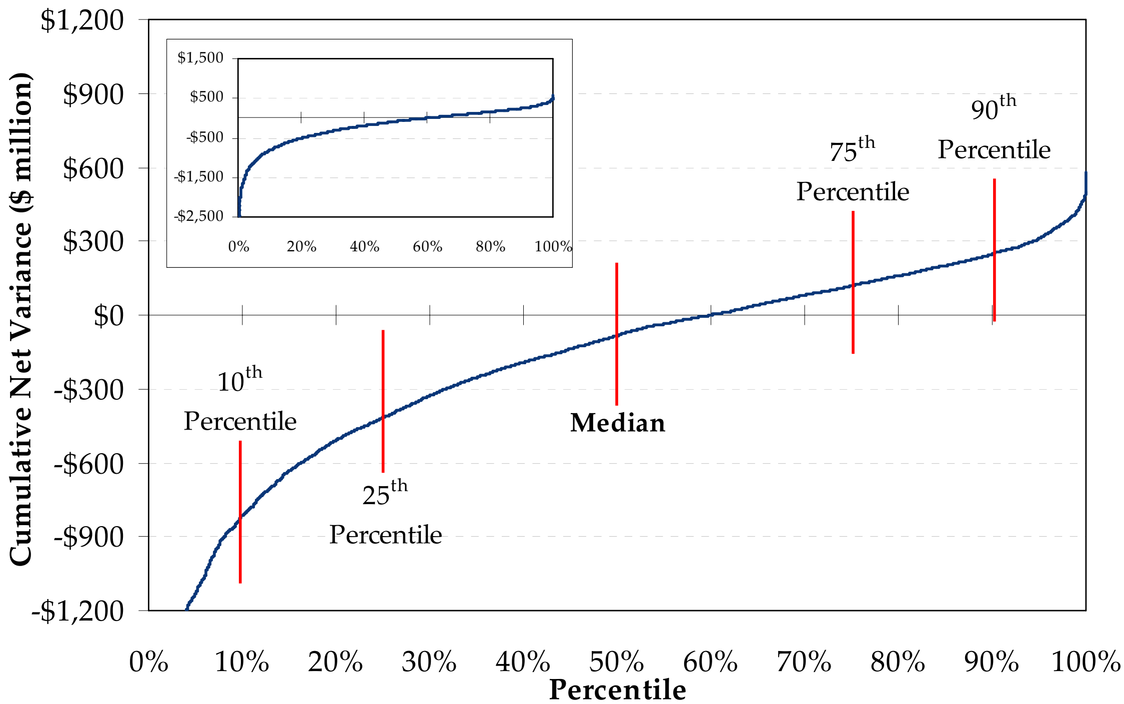
17 The results of the high/low gas price sensitivity are provided in the Navigant Consulting Ontario Wholesale Electricity Market Price Forecast Report.

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, 25, 50th, 75th, and 90th percentiles.

Figure 11: Cumulative Variances over Entire Term



Source: NCI

The median variance, which represents the adjustment that will be applied to the RPA, was found to be negative $85 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.