

Regulated Price Plan

Price Report

November 1, 2016

to

October 31, 2017

Ontario Energy Board

October 14, 2016

Executive Summary

This report contains the electricity commodity prices under the Regulated Price Plan (RPP) for the period November 1, 2016 through October 31, 2017. The prices were developed using the methodology described in the Regulated Price Plan Manual (RPP Manual).

In accordance with the applicable regulation, the OEB must forecast the cost of supplying RPP consumers and ensure that RPP prices reflect this cost. RPP prices are reviewed by the OEB every six months to determine if they need to be adjusted. After detailed review of the expected costs in the upcoming 12 month period, as well as assessing the variances between actual and forecast costs since prices were last established, the OEB has determined that the prices set in April 2016 continue to be effective in recovering the forecast costs attributable to customers on the Regulated Price Plan. Accordingly, no adjustments are required at this time. The determination to retain current prices supports the OEB's objectives of providing fair, stable and predictable commodity prices for consumers.

Regular seasonal adjustments to TOU periods and tier thresholds will still apply.

Forecasting Methodology

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

1. Forecasting the total RPP supply cost for 12 months, 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:

- o the hourly market price of electricity;
- o the electricity consumption pattern of RPP consumers;
- o the electricity supplied by those assets of Ontario Power Generation (OPG) whose price is regulated;
- o the costs related to the contracts signed by non-utility generators (NUGs) with the former Ontario Hydro;
- o the costs of the supply contracts, and conservation and demand management (CDM) initiatives of the Independent Electricity System Operator¹ (IESO); and
- o the net variance account balance (as of October 31, 2016) carried by the IESO.

The 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

¹ Contracts were formerly held by the Ontario Power Authority (OPA), which merged with the Independent Electricity System Operator effective January 1, 2015.

consumers, who represent most 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). This consumption pattern makes the average market price for RPP consumers higher than the average market price for the entire Ontario electricity market.

Average RPP Supply Cost

The hourly market price forecast was developed by Navigant Consulting Ltd. (Navigant). The forecast of the simple average market price for 12 months from November 1, 2016 is \$22.59/MWh (2.259 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 \$24.63/MWh (2.463 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 summarized by the Global Adjustment. The Global Adjustment reflects the impact of the NUG contract costs, which are above market prices at most times, the regulated prices for OPG's prescribed nuclear and hydroelectric generating facilities (the prescribed assets), which may be above or below market prices, and any remaining cost of supply contracts held by the Independent Electricity System Operator (IESO) which generators have not recovered through their market revenues. The cost associated with Conservation and Demand Management (CDM) initiatives implemented by the IESO is also included. The forecast net impact of the Global Adjustment is to increase the average RPP supply cost by \$84.50/MWh (8.450 cents per kWh).

Another factor 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. Two adjustments are made to account for this forecast variance. A small adjustment is made to the RPP supply cost to account for the fact that these random effects are more likely to increase than to decrease costs. This adjustment was determined to be \$1.00/MWh (0.100 cents per kWh). Without this adjustment, the RPP would be expected to end the year with a small debit variance.

An additional adjustment factor is required to "clear" the expected balance in the IESO variance account as of October 31, 2017. The current balance accumulated due to lower than previously forecast RPP revenues and higher than previously forecast supply costs. The forecast adjustment factor to clear the existing variance balance is a debit (increase in the RPP price) of \$2.26/MWh (0.226 cents per kWh).

The resulting average RPP supply cost (for the period starting November 1, 2016) is \$112.39/MWh. The average RPP price (RPA) is 11.24 cents per kWh, 0.1 cents higher than the forecast for 12 months beginning May 2016. This is summarized in Table ES-1.

Table ES-1: Average RPP Supply Cost Summary (for the 12 months from May 1, 2016)

<i>RPP Supply Cost Summary</i>	
for the period from November 1, 2016 through October 31, 2017	
Forecast Wholesale Electricity Price	\$22.59
Load-Weighted Price for RPP Consumers (\$ / MWh)	\$24.63
Impact of the Global Adjustment (\$ / MWh)	+ \$84.50
Adjustment to Address Bias Towards Unfavourable Variance (\$ / MWh)	+ \$1.00
Adjustment to Clear Existing Variance (\$ / MWh)	+ \$2.26
Average Supply Cost for RPP Consumers (\$ / MWh)	= \$112.39

Source: Navigant

Inevitably, there will be a difference between the actual and forecast cost of supplying electricity to all RPP consumers. Differences can arise as a result of changes in demand due to weather, variation in natural gas prices, changes in the supply mix, as well as other factors. The sum of these differences 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. Rather, they pay prices under price structures that are designed to make their consumption weighted average price equal to the average supply cost. There are two RPP price structures, one for consumers with eligible time-of-use (or “smart”) meters who pay time-of-use (TOU) prices, who make up the majority of RPP consumers, and one for consumers with conventional meters (Tiered Pricing).

Regulated Price Plan (TOU Pricing)

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 price structure. The prices for this plan are based on three time-of-use periods per weekday². 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 OEB establishes its time of use prices with reference to the objectives enumerated in its RPP manual. The OEB has a number of objectives in setting the RPP. These include setting prices to recover the full cost of RPP supply on a forecast basis, as well as ensuring that prices are fair, stable and predictable. The OEB has determined that the TOU prices will not change from the previous period because they will continue to be effective in recovering forecast costs. The review of forecast costs has shown the average RPP cost for the next 12 months to be within 1% of the last 12-month forecast, and that variances between the last forecast and actual costs have been broadly in line with expectations. TOU prices generated by the current cost forecast are similarly only slightly different from those set as of May 1, 2016.

The resulting time-of-use (TOU) prices for consumers with eligible time-of-use meters therefore remain at:

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

- o $RPEM_{OFF} = 8.7$ cents per kWh;
- o $RPEM_{MID} = 13.2$ cents per kWh; and,
- o $RPEM_{ON} = 18.0$ cents per kWh.

These prices reflect the seasonal change in the TOU pricing periods which will take effect on November 1, 2016 and May 1, 2017. TOU pricing periods are:

- o *Off-peak* period (priced at $RPEM_{OFF}$):
 - *Winter and summer weekdays*: 7 p.m. to midnight and midnight to 7 a.m.
 - *Winter and summer weekends and holidays*:³ 24 hours (all day)
- o *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 7 p.m.
- o *On-peak* period (priced at $RPEM_{ON}$)
 - *Winter weekdays*: 7 a.m. to 11 a.m. and 5 p.m. to 7p.m.
 - *Summer weekdays*: 11 a.m. to 5 p.m.

Regulated Price Plan - Tiered Pricing

RPP consumers that are not on TOU pricing pay prices in two tiers; one price (referred to as $RPCM_{T1}$) for monthly consumption up to a tier threshold and a higher price (referred to as $RPCM_{T2}$) 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.

Tiered prices calculated from the forecast RPP average cost in this report are each 0.1 cents higher than current prices paid by RPP customers. Since current prices will continue to be effective in recovering forecast costs, taking expected variances into account, the OEB has determined that tiered prices will also remain unchanged at this time. The tiered prices for consumers with conventional meters therefore remain as follows:

- o $RPCM_{T1} = 10.3$ cents per kWh, and
- o $RPCM_{T2} = 12.1$ cents per kWh.

³ For the purpose of RPP time-of-use pricing, a “holiday” means 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 (that is not also a holiday) is to be treated as the holiday for RPP time-of-use pricing purposes.

Based on historical consumption, approximately 53% of RPP tiered consumption is forecast to be at the lower tier price (RPCM_{T1}) and 47% at the higher tier price (RPCM_{T2}). Given these proportions, the average price for conventional meter RPP consumption is forecast to be equal to the RPA.

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-2.⁴

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

Time-of-Use RPP Prices	Off-Peak	Mid-Peak	On-Peak	Average Price
Price	8.7¢	13.2¢	18.0¢	11.1¢
% of TOU Consumption	65%	17%	18%	
Tiered RPP Prices	Tier 1		Tier 2	Average Price
Price	10.3¢		12.1¢	11.1¢
% of Tiered Consumption	53%		47%	

Major Factors Influencing RPP Prices

The forecast average supply cost for RPP consumers increases by \$0.97/MWh, or 0.87%, in the current forecast compared to the previous forecast. Two factors account for this change:

- o Underlying cost factors - the load weighted market price for RPP consumers plus the Global Adjustment - decrease the average supply cost by \$0.32/MWh; and,
- o The change in the variance account debit balance adds to the supply cost increase by \$1.29/MWh.

The net difference in the forecast average supply cost for RPP customers is sufficiently small that RPP prices developed for the prior forecast period remain effective at recovering the expected costs over the current forecast period.

⁴The percentages of total consumption by TOU period and Tiers in Table ES-2 are based on several years of consumption data for consumers provided by the IESO.

Table of Contents

EXECUTIVE SUMMARY	2
AVERAGE RPP SUPPLY COST	3
REGULATED PRICE PLAN (TOU PRICING)	4
REGULATED PRICE PLAN - TIERED PRICING	5
LIST OF FIGURES & TABLES	7
1. INTRODUCTION.....	8
1.1 ASSOCIATED DOCUMENTS.....	8
1.2 PROCESS FOR RPP PRICE DETERMINATIONS	9
2. CALCULATING THE RPP SUPPLY COST	10
2.1 DEFINING THE RPP SUPPLY COST	10
2.2 COMPUTATION OF THE RPP SUPPLY COST.....	11
2.2.1 Forecast Cost of Supply Under Market Rules	12
2.2.2 RPP Share of the Global Adjustment	13
2.2.3 Cost Adjustment Term for Prescribed Generators	13
2.2.4 Cost Adjustment Term for Non-Utility Generators (NUGs) and Other Generation under Contract with OEFC	14
2.2.5 Cost Adjustment Term for Certain Renewable Generation Under Contract with the IESO	14
2.2.6 Cost Adjustment Term for Other Contracts with the IESO.....	15
2.2.7 Estimate of the Global Adjustment.....	17
2.2.8 Cost Adjustment Term for IESO Variance Account.....	18
2.3 CORRECTING FOR THE BIAS TOWARDS UNFAVORABLE VARIANCES	18
2.4 TOTAL RPP SUPPLY COST	19
3. CALCULATING THE RPP PRICE.....	21
3.1 SETTING THE TOU PRICES FOR CONSUMERS WITH ELIGIBLE TIME-OF-USE METERS	21
3.2 SETTING THE TIERED PRICES.....	23
4. EXPECTED VARIANCE.....	24

List of Figures & Tables

List of Figures

Figure 1: Process Flow for Determining the RPP Price.....	9
Figure 2: Components of the RPP Supply Cost.....	17
Figure 3: Expected Monthly Variance Account Balance (\$ million).....	25

List of Tables

Table 1: Ontario Electricity Market Price Forecast (\$ per MWh)	12
Table 2: Total Electricity Supply and Costs	20
Table 3: Average RPP Supply Cost Summary	21
Table 4: Price Paid by Average RPP Consumer under Tiered and TOU RPP Prices	24

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) was mandated to develop a regulated price plan (RPP) for electricity prices to be charged to consumers that have been designated by legislation and that have not opted to switch to a retailer or to be charged the hourly spot market price. The first prices were implemented under the RPP effective on April 1, 2005, as set out by the Ontario Government in regulation O. Reg. 95/05. This report covers the period from November 1, 2016 to October 31, 2017. The RPP prices set out in this report are intended to be in place for that same period.⁵ However, the OEB will review these RPP prices in six months to determine whether they need to be adjusted.

The OEB has issued a Regulated Price Plan Manual (RPP Manual⁶) that explains how RPP prices are set. The OEB relies on a forecast of wholesale electricity market prices, prepared by Navigant as a basic input into the forecast of RPP supply costs as per the RPP Manual methodology.

This Report describes how the OEB has used the RPP Manual's processes and methodologies to arrive at the RPP prices effective November 1, 2016.

This Report consists of four chapters as follows:

- o Chapter 1. Introduction
- o Chapter 2. Calculating the RPP Supply Cost
- o Chapter 3. Calculating RPP Prices
- o Chapter 4. Expected Variance

1.1 Associated Documents

Two documents are closely associated with this Report:

- o The *Regulated Price Plan Manual* (RPP Manual) describes the methodology for setting RPP prices; and,
- o The *Ontario Wholesale Electricity Market Price Forecast For the Period November 1, 2016 through April 30, 2018* (Market Price Forecast Report),⁷ prepared by Navigant, contains the Ontario wholesale electricity market price forecast and explains the material

⁵ In accordance with the RPP Manual, price resetting is considered for implementation every six months. If there is a price resetting following an OEB review, the OEB 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 IESO 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 a significant unexpected variance arises..

⁶http://www.ontarioenergyboard.ca/OEB/_Documents/EB-2004-0205/RPP_Manual.pdf

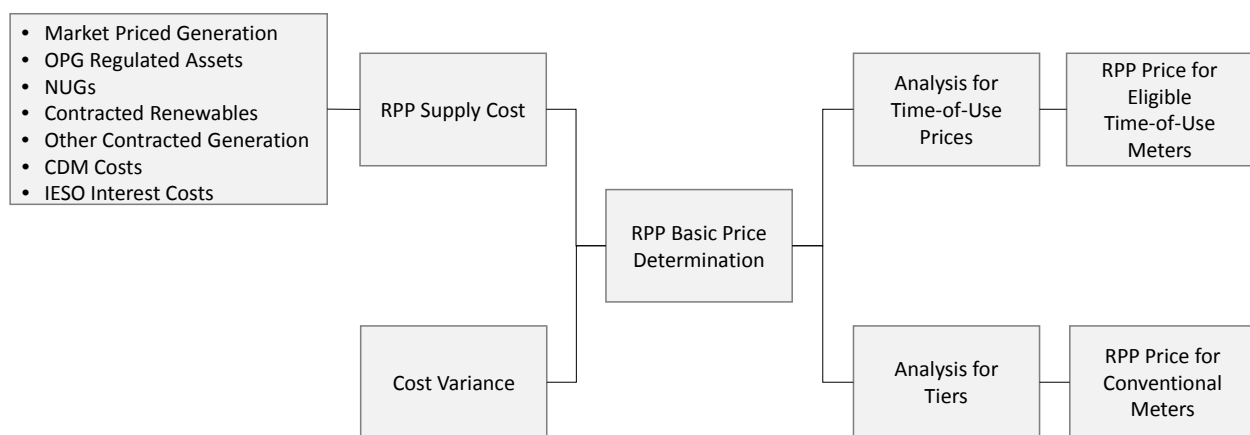
⁷ The Market Price Forecast Report is posted on the OEB web site, along with the RPP Price Report, on the RPP web page. http://www.ontarioenergyboard.ca/oeb/_Documents/EB-2004-0205/Wholesale_Price_Forecast_Report_November2016.pdf

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 Independent Electricity System Operator, or the IESO) 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 the terms in Equation 1. Most of the terms depend on more than one underlying data source or assumption. This chapter describes the data or assumption source for each of the terms and explains 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 the elements of 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. This equation is further explained in the RPP Manual.

Equation 1

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

- o C_{RPP} is the total RPP supply cost;
- o M is the amount that the RPP supply would have cost under the Market Rules;
- o α is the RPP proportion of the total Global Adjustment costs;⁸
- o A is the amount paid to prescribed generators in respect of the output of their prescribed generation facilities;⁹
- o B is the amount those generators would have received under the Market Rules;
- o C is the amount paid to the Ontario Electricity Finance Corporation (OEFC) with respect to its payments under contracts with non-utility generators (NUGs);
- o D is the amount that would have been received under the Market Rules for electricity and ancillary services supplied by those NUGs;
- o E is the amount paid to the IESO with respect to its payments under certain contracts with renewable generators;

⁸The elements in square brackets collectively represent the Global Adjustment. For RPP price setting purposes the elements of the Global Adjustment are described differently in this Price Report than they are in O. Reg. 429/04 (Adjustments under Section 25.33 of the Act) made under the *Electricity Act, 1998*. “G” in the expression in square brackets integrates two separate components of the Global Adjustment formula (G and H). “E” and “F” in the expression in square brackets include certain generation contracts that are associated with “G” in O. Reg. 429/04. This is necessary to ensure that there is no double-counting and thus over-recovery of generation costs because all RPP supply is included in “M”. As discussed below, forecast Global Adjustment costs are recovered through the RPP according to the allocation of the Global Adjustment between Class A and Class B consumers, and the RPP consumers’ share of Class B consumption.

⁹As set out in regulation O. Reg. 53/05, The Board sets payment amounts for energy produced from Ontario Power Generation’s nuclear and certain hydro-electric generating stations (the prescribed assets). The Board’s most recent Decision setting these payment amounts (EB-2014-0370) was issued on October 8, 2015.

- o F the amount that would have been received under the Market Rules for electricity and ancillary services supplied by those renewable generators;
- o G is (a) the amount paid by the IESO for its other procurement contracts for generation or for demand response or CDM, and (b) the sum of any OEB-approved amounts for CDM programs that are payable by the IESO to distributors; and,
- o H is the amount associated with the variance account held by the IESO. 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 OEB 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 (October 31, 2016).¹⁰ This amount is included in Equation 1 ("H").

In May 2016, the *Climate Change Mitigation and Low-carbon Economy Act, 2016* received Royal Assent and Ontario Regulation 144/16 was issued. Together, the legislation and regulation provide details about the Cap and Trade Program, which begins January 1, 2017. Under the legislation, large final emitters, natural gas distributors and electricity importers will be required to verify and report their greenhouse gas emissions to the provincial government, and will have to match their total emissions in each compliance period with an equivalent amount of "allowances."

Accordingly, this RPP forecast makes provision for the cap and trade program being in place for ten of the twelve months in this forecast, starting in January. As more fully detailed in the Wholesale Market Forecast report, the forecast of wholesale market prices reflects the expectation for a carbon market aligned with prices in California and Quebec. Likewise, the estimate of Global Adjustment in this report reflects the effects of higher market prices.

¹⁰ RPP prices are announced in advance by the OEB 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 following sections 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:

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

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

- o 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
- o 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 Market Price Forecast Report. That report also contains a detailed explanation of the assumptions that underpin the forecast such as generator fuel prices (e.g. 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	Nov 16 - Jan 17	\$32.20	\$19.13	\$25.09	
	Q2	Feb 17 - Apr 17	\$32.04	\$19.17	\$25.08	
	Q3	May 17 - Jul 17	\$27.40	\$13.05	\$19.67	
	Q4	Aug 17 - Oct 17	\$28.23	\$14.26	\$20.61	
Other	Q1	Nov 17 - Jan 18	\$32.26	\$18.87	\$24.97	
	Q2	Feb 18 - Apr 18	\$25.58	\$13.66	\$19.14	

Source: Navigant, *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 definition of “on-peak” and “off-peak” hours for this purpose bears no relation to the “on-peak”, “mid-peak” and “off-peak” periods used for time-of-use pricing.

The forecasts of the monthly ratios of load-weighted vs. simple average HOEP are based on actual prices between April 2005 and September 2016. The on-peak to off-peak ratio is also based on data through September 2016.

As shown in Table 1, the forecast simple average HOEP for the period November 1, 2016 to October 31, 2017 is \$22.59/MWh (2.259 cents per kWh). The forecast of the load weighted average price for RPP consumers (“M” in Equation 1) is \$24.63/MWh (2.463 cents per kWh), or \$1.4 billion in total, the result of RPP consumers having load patterns that are more peak oriented than the overall system.

2.2.2 RPP Share of the Global Adjustment

Alpha (“ α ”) in Equation 1 represents the share of the Global Adjustment paid by (or credited to) RPP consumers. Effective January 1, 2011, O. Reg. 429/04 (Adjustments under Section 25.33 of the *Act*) made under the *Electricity Act*, 1998 was amended to revise how Global Adjustment costs are allocated to two sets of consumers, Class A and Class B (includes RPP consumers)¹¹.

The first step to determine alpha is to estimate Class A’s share of the Global Adjustment. Based on the formula and periods defined in O. Reg. 429/04, the Class A share has been decreased to 11.7% for the July 2016 to June 2017 period; and it is assumed for the purposes of this forecast to remain at that level for the July 2017 to June 2018 period.¹² Class B’s share of the Global Adjustment is therefore 88.3%.

The next step is to estimate RPP consumers’ share of Class B consumption. Based on historical data on RPP consumption as a share of total Ontario consumption, it is forecast that RPP consumption will represent about 59 TWh or 52.1% of total Class B consumption.¹³ The RPP share varies from month to month, ranging between 50.5% and 54.2%. The value of α therefore ranges between 0.446 and 0.478. Over the entire RPP period, RPP consumers are forecast to be responsible for 46.0% of the Global Adjustment.

2.2.3 Cost Adjustment Term for Prescribed Generators

This section covers the second term of Equation 1:

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

The prescribed generators are comprised of the rate-regulated nuclear and hydroelectric facilities of Ontario Power Generation (OPG). The amounts paid for the prescribed generation as set out in the EB-2013-0321 Payment Amounts Order dated December 18, 2014 is \$59.29/MWh for nuclear generation, \$40.20/MWh for prescribed hydroelectric generation and \$41.93/MWh for the newly prescribed hydroelectric generation.

OPG filed an application (EB-2014-0370) for the clearance of certain deferral and variance account balances. On September 10, 2015, the OEB approved payment amounts riders that were made effective July 1, 2015 with an implementation date of October 1, 2015. The amounts approved for the nuclear and hydroelectric generation facilities are \$777.1 million and \$155.6 million respectively and will be recovered until December 2016. The RPP forecast includes a proportionate share of these costs being recovered through December 31, 2016. No charges related to the EB-2014-0370 application are included in the RPP forecast from January through October, 2017.

¹¹ O. Reg. 429/04 defines two classes of consumers; Class A, comprised of consumers whose maximum hourly demand for electricity in a month is 5 MW or more; and Class B consumers, comprised of all other consumers, including RPP consumers. Subsequent to this, O. Reg. 126/14 redefined the demand threshold and allows certain load facilities with an average monthly peak load of 3-5 MW to become eligible to be a Class A customer on an opt-in basis, effective July, 2015.

¹² The percentage of Class A Global Adjustment costs was based on Class A load during peak demand hours in the May 1, 2015 to April 30, 2016 period. The Class A peak demand factor effective for the July 1, 2016 to June 30, 2017 period will be based on peak load percentages in the May 1, 2015 to April 30, 2016 period.

¹³ The Class A/Class B split did not exist before January 2011. Data on RPP consumption as a share of total Class B consumption is available only for the January 2011 to September 2016 period.

On May 27, 2016, OPG filed an application (EB-2016-0152) seeking approval for payment amounts for its prescribed generation facilities commencing January 1, 2017 through to the end 2021. Consistent with past practice, the OEB has assessed whether it is prudent to take into account some effect of the application in this RPP forecast. This approach is in keeping with one of the objectives of the RPP, which is to smooth changes in prices over time. The OEB has concluded that, given that the review of this application remains in the early stages, no provisions for OPG's application have been included in this forecast. Current payment amounts are assumed to persist in real terms through to the end of the forecast period.

Quantity A was therefore forecast by multiplying payment amounts per MWh consistent with the assumption described above, by the prescribed assets' total forecast output per month in MWh.

Quantity B was forecast by estimating the market values of each MWh of nuclear and prescribed hydraulic generation, and multiplying those market values by the volume of nuclear and prescribed hydraulic generation. The value of A is \$4.0 billion, and the value of B is \$1.7 billion.

2.2.4 Cost Adjustment Term for Non-Utility Generators (NUGs) and Other Generation under Contract with the OEFC

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

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

Although the details of these payments (amounts by recipient, volumes, etc.) are not public, published information from the IESO about aggregate monthly payments to non-utility generators (NUGs) has been used as the basis for forecasting payments in future months. This data has been supplemented by information provided by the OEFC. This forecast was used to compute an estimate of the total payments to the NUGs under their contracts, or amount C in Equation 1.

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.

The value of "C" in Equation 1 (i.e., the contract cost of the NUGs) is estimated to be \$0.6 billion, and the value of "D" (i.e., the market value of the NUG output) is estimated to be \$0.1 billion.

2.2.5 Cost Adjustment Term for Certain Renewable Generation Under Contract with the IESO

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

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

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

- o Renewable Energy Supply (RES) Request for Proposals (RFP) Phases I, II and III;
- o the Renewable Energy Standard Offer Program (RESOP);
- o the Feed-In Tariff (FIT) Program;

- o the Hydroelectric Energy Supply Agreements (HESA) directive, covering new and redeveloped hydro facilities; and,
- o the Hydro Contract Initiative (HCI), covering existing hydro plants.

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 IESO. 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).¹⁴

The size and generation type of the successful renewable energy projects to date have been announced by the Government and the IESO. 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 (based on market prices in the Wholesale Market Price Forecast Report) at the time that output is generated.

The value of "E" in Equation 1 (i.e., the contract cost of renewable generation) is estimated to be \$4.2 billion, and the value of "F" (i.e., the market value of renewable generation) is estimated to be \$0.1 billion.

2.2.6 Cost Adjustment Term for Other Contracts with the IESO

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

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

The costs for three types of resources under contract with the IESO 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 and B nuclear facilities.

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

¹⁴For information related to the FIT Price Schedule, see the IESO's dedicated web page at: <http://fit.powerauthority.on.ca/program-resources/price-schedule>

- o Clean Energy Supply (CES) contracts, which include conventional generation contracts as well as one demand response contract awarded to Loblaw's;¹⁵
- o The "early mover" contracts;¹⁶
- o Contracts awarded for projects classified as Combined Heat and Power (CHP) projects¹⁷.

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 Report that underpins this RPP price setting activity. The NRRs and other contract parameters for each contract have been estimated based on publicly available information. Examples include the average NRR for the CES contracts which was announced by the Government to be \$7,900 per megawatt-month,¹⁸ as well as an NRR of \$17,000 for the cancelled Oakville Generating station which has been used as a guideline for some of the more recent gas plant additions.

The cost to the IESO of any additional CDM initiatives is also captured in term G of Equation 1. Starting on January 1, 2015, and continuing until December 31, 2020, electricity distributors are expected to continue to offer CDM programs to customers in their service area, consistent with the Minister of Energy's Directive issued to the OEB and the Letter of Direction to the OPA, both dated March 31, 2014. Costs for these programs will be recovered and settled with the IESO, by way of contracts with the LDCs, for the period 2015 to 2020.

In December 2015, the IESO negotiated an amended agreement with Bruce Power in relation to the refurbishment and continued operation of the Bruce Power nuclear units¹⁹. The amended contract stipulates that an initial price of \$65.73/MWh would be paid for the output of Bruce A and B. The amended contract also stipulates that the initial price will be indexed to inflation

¹⁵ Nine facilities holding CES contracts are operational during this RPP period: the GTAA Cogeneration Facility, the Loblaw's Demand Response Program, seven large gas-fired plants (Portlands, Goreway, Greenfield, St. Clair, York Energy Centre, Halton Hills and Green Electron Power), and two biomass projects (Atikokan and Thunder Bay). The IESO entered into contracts with these facilities pursuant to directives from the Minister of Energy.

¹⁶ 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. On December 24, 2008, the OPA was directed to negotiate new contracts which are to expire no later than December 26, 2026. For forecasting purposes, it is assumed that the contribution to the Global Adjustment of these contracts will be similar to what it would have been under the old contracts.

¹⁷ Seven facilities holding CHP Phase I contracts are expected to be operational during this RPP period: the Great Northern Tri-gen Facility, the Durham College District Energy Project, the Countryside London Cogeneration Facility, the Warden Energy Centre, the Algoma Energy Cogeneration Facility, the East Windsor Cogeneration Centre, and the Thorold Cogeneration Project. Other facilities from other procurement processes are included as well.

¹⁸ Given the Ministerial directive to the OPA, the NRR for the "early movers" was assumed to be the same.

¹⁹ In 2005, Bruce Power entered into an initial Bruce Power Refurbishment Implementation Agreement (BPRIA) in relation to the operation of Bruce Units 1 and 2. In December 2015, the IESO and Bruce Power entered into an Amended and Restated Bruce Power Refurbishment Implementation Agreement (AR-BPRIA).

every April 1. For the upcoming RPP period, these revised contract terms have been applied for the output of Bruce A and B.

The IESO has a contract with OPG for the on-going operation of OPG's Lennox Generating Station, a 2,140-MW peaking plant. The cost of this contract is included in the "G" variable.

The value of "G" in Equation 1 (i.e., net cost of Bruce nuclear, gas and Lennox generation plus CDM programs) is estimated to be \$3.9 billion.

2.2.7 Estimate of the Global Adjustment

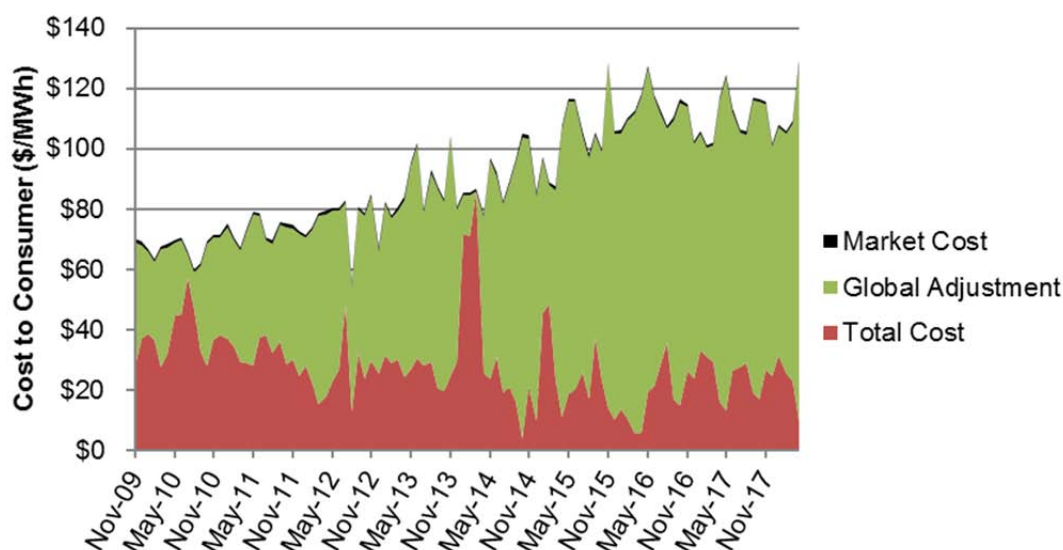
The total Global Adjustment is estimated to be a cost of \$10.8 billion. The RPP share of this (i.e., α times the total cost) is estimated to be a cost of \$5.0 billion, or \$84.50/MWh (8.450 cents per kWh). This is the forecast of the average Global Adjustment cost per unit that will accrue to RPP consumers over the period from November 1, 2016 to October 31, 2017.

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

- o changes (usually increases) in the number and aggregate capacity of contracts it covers, or
- o fluctuations in the market revenues earned by contracted and prescribed generation.

This is illustrated in Figure 2, which shows how the Global Adjustment is expected to change over the next 18 months. 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 total supply cost (market cost plus Global Adjustment) is expected to slightly decrease over the next 12 months.

Figure 2: Components of the RPP Supply Cost



Overall, supply costs have remained essentially stable between this RPP period and the previous one. Underlying costs have decreased due to the expiry of temporary one-time costs for prescribed assets at the end of 2016. However, that decrease is largely offset by an increase

in costs related primarily to new renewable sources of generation. Similarly, higher wholesale market prices result in only a slight increase in supply cost because they are largely offset by a decrease in the Global Adjustment.

2.2.8 Cost Adjustment Term for IESO Variance Account

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

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

The cost adjustment term for the IESO 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 (November 2016 – October 2017). 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 IESO to carry consumer debit variances in some months are generally offset by interest income the IESO receives from carrying consumer credit balances in other months. In addition, the interest rate paid by the IESO 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 October 31, 2016 the net variance account balance is forecast to be a negative balance (i.e. a deficit) of approximately \$82 million including interest. This is quantity “H” in Equation 1.

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 October 31, 2016. This variance clearance factor has increased from a debit of 0.097 cents per kWh in the previous RPP report to a debit of 0.226 cents per kWh, based on costs and market activity from April 2016 through to September 2016. The values also reflect an adjustment to reflect a revision to certain non-utility generation costs. Offsetting this increase somewhat is a variance account balance that is currently higher than previously forecast. This difference is due to a warmer summer that resulted in higher market prices than forecast and generated more revenue than forecast due to higher system demand. At the same time, system costs, many of which are fixed, were recovered over more consumption. As a result, the debit that had accumulated in the variance account was drawn down faster than expected. The variance clearance factor increases the average RPP supply cost by the amount of the debit: \$2.26/MWh (0.226 cents per kWh).

2.3 Correcting for the Bias Towards Unfavorable Variances

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 supply less energy than forecast (due to unscheduled outages) than to supply more than forecast (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.

The OEB regularly reviews the differences between the estimated and actual RPP supply cost. Based on this experience, the Adjustment to Address Bias Towards Unfavourable Variance is set at \$1.00/MWh (0.100 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

Table 2 shows the percentage of Ontario's total electricity supply attributable to various generation sources, the percentage of forecasted Global Adjustment costs for each type of generation and the total unit costs. Total unit costs are based on contracted costs for each generation type, including global adjustment payments and market price payments, where applicable.

Table 2: Total Electricity Supply and Cost

	% of Total Supply	% of Total GA	Total Unit Cost (Cents/kWh)
Nuclear	59%	38%	6.6
Hydro	23%	12%	5.8
Gas	7%	17%	17.3
Wind	8%	18%	14.0
Solar	2%	15%	48.0
Bio Energy	0%	0%	13.1

NB: Hydro excludes NUGs and OPG non-prescribed generation. Gas includes Lennox, NUGs and OPG bioenergy facilities. Percentage (%) of Total GA excludes CDM costs.

The total RPP supply cost is estimated to be \$6.5 billion.²⁰

The following table itemizes the various steps discussed above to arrive at the average RPP supply cost of \$112.39/MWh. This average supply cost corresponds to an average RPP price, which is referred to as RPA, of 11.24 cents per kWh.

²⁰ The total cost figure is net of the forecast variance account balance as of October 31, 2016.

Table 3: Average RPP Supply Cost Summary

<i>RPP Supply Cost Summary</i>		
for the period from November 1, 2016 through October 31, 2017		
Forecast Wholesale Electricity Price		\$22.59
Load-Weighted Price for RPP Consumers (\$ / MWh)		\$24.63
Impact of the Global Adjustment (\$ / MWh)	+	\$84.50
Adjustment to Address Bias Towards Unfavourable Variance (\$ / MWh)	+	\$1.00
Adjustment to Clear Existing Variance (\$ / MWh)	+	\$2.26
Average Supply Cost for RPP Consumers (\$ / MWh)	=	\$112.39

Source: Navigant

RPP prices currently being paid by RPP customers are set to recover an RPA of 11.14 cents per kWh. These prices reflected a total RPP cost pool of \$6.5 billion and RPP consumption of 58 TWh. Each of these parameters is virtually equal to the forecast prepared in this report. Given the results of this forecast, it is expected that the RPP prices previously set in April 2016 will continue to be effective in recovering the cost of electricity supply for RPP customers over the forecast period.

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 explains how prices are determined for consumers with eligible time-of-use meters that are being charged the TOU prices, $RPEM_{ON}$, $RPEM_{MID}$, and $RPEM_{OFF}$, and for the tiers, $RPCM_{T1}$ and $RPCM_{T2}$.

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

For those consumers with eligible time-of-use meters, three separate prices 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 described in the RPP Manual, the three prices are calculated to recover the full costs of supply, given the load shape of TOU customers. The RPP Manual does not prescribe the order in which prices are determined.

The first step in deriving the TOU prices for this forecast period was to set the Off-peak price, or $RPEM_{OFF}$. This price reflects the forecast market price during that period, including the Global Adjustment and the variance clearance factor. The Mid-peak price, $RPEM_{MID}$, was similarly set. After these two prices were set, and given the forecast levels of consumption during each of the 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 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, most 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, because the purpose of the demand management portion of CDM is to ensure uninterrupted supply during peak times. Payments to Lennox are also allocated to the on-peak period, for the same reason. Payments to natural gas generators have been allocated into the mid-peak and on-peak periods. Though the gas generators operate in all three periods, costs for generation in off-peak times have been allocated to the on-peak period, reflecting the system purpose for which many of the facilities were initially contracted: ensuring reliability of supply and being a dispatchable source of power at times of higher demand. The NUG component of the GA is allocated to both Mid-peak and On-peak consumption because these generators 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 because the majority of risks covered by the adjustment are borne during these time periods.

The overall effect of this allocation is to increase the differential between the on-peak and off-peak prices to 2.1:1. This ratio, which is higher than in many RPP settings prior to May 2015, strengthens the incentive for electricity consumers to shift their consumption away from on-peak periods, when their electricity prices are highest. Not only is the on-peak price higher under this scenario, but the off-peak price is also lower than it would have been absent this increase to the ratio. A customer with a consumption pattern that mirrors the total TOU

consumption would experience no overall bill impact from this change to the ratio, since each of the TOU prices are set so that they collectively recover the same average cost.

The OEB has a number of objectives in setting the RPP. These include setting prices to recover the full cost of RPP supply on a forecast basis, as well as ensuring that prices are fair, stable and predictable.

The review of costs has shown the average RPP cost for the next 12 months to be within 1% of the last 12 month forecast. Variances over the last six months, from March 2016 to August 2016, have tracked within an average of \$6 million relative to the expected values.

The time of use prices that result from the current forecast are 8.8 cents per kWh off-peak; 13.3 cents for mid peak and 18.3 cents for on-peak. TOU prices calculated from this average cost are only marginally (0.1-0.3) cents higher than current TOU prices; the difference in revenues collected over the next six months is negligible in the context of the RPP cost overall, which is forecast to be about \$6.5 billion annually. The difference is also smaller than the typical unexpected variance that can arise from weather variation, fluctuation in natural gas prices, and other cost inputs.

The OEB has determined that the TOU prices will not change from the previous period because they will continue to be effective in recovering forecast costs. The determination to retain current prices supports the OEB's objectives of providing fair, stable and predictable commodity prices for consumers. The **time-of-use prices** therefore remain as follows:

- o $RPEM_{OFF} = 8.7$ cents per kWh
- o $RPEM_{MID} = 13.2$ cents per kWh, and
- o $RPEM_{ON} = 18.0$ cents per kWh.

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

- o *Off-peak* period (priced at $RPEM_{OFF}$):
 - *Winter and summer weekdays*: 7 p.m. to midnight and midnight to 7 a.m.
 - *Winter and summer weekends and holidays*:²¹ 24 hours (all day)
- o *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 7 p.m.
- o *On-peak* period (priced at $RPEM_{ON}$)
 - *Winter weekdays*: 7 a.m. to 11 a.m. and 5 p.m. to 7p.m.
 - *Summer weekdays*: 11 a.m. to 5 p.m.

²¹ For the purpose of RPP time-of-use pricing, a "holiday" means 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 (that is not also a holiday) is to be treated as the holiday for RPP time-of-use pricing purposes.

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

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 an average 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. This average price is equal to the RPA.

3.2 Setting the Tiered Prices

The final step in setting the price for RPP consumers with conventional meters is to determine the tiered 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 tiered 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.

RPP tiered prices are set such that the weighted average price will come as close as possible to the RPA, based on the forecast ratio of Tier 1 to Tier 2 consumption, and maintaining a 15-17% difference between Tier 1 and Tier 2 prices.

Tiered prices calculated from the forecast RPP average cost in this report are each 0.1 cents higher than current prices paid by RPP customers. The OEB has determined that the tiered prices will not change from the previous period because they will continue to be effective in recovering forecast costs. The determination to retain current prices supports the OEB's objectives of providing fair, stable and predictable commodity prices for consumers. The **tiered prices** therefore remain as follows:

- o $RPCM_{T1}$ = 10.3 cents per kWh; and,
- o $RPCM_{T2}$ = 12.1 cents per kWh.

Table 4: Price Paid by Average RPP Consumer under Tiered and TOU RPP prices

Time-of-Use RPP Prices	Off-Peak	Mid-Peak	On-Peak	Average Price
Price	8.7¢	13.2¢	18.0¢	11.1¢
% of TOU Consumption	65%	17%	18%	
Tiered RPP Prices	Tier 1		Tier 2	Average Price
Price	10.3¢		12.1¢	11.1¢
% of Tiered Consumption	53%		47%	

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:

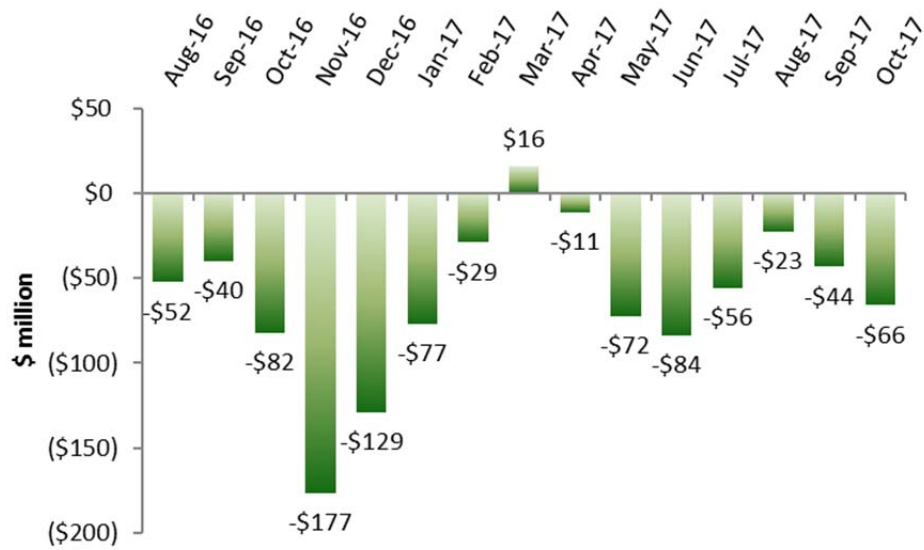
- o Variance clearance will tend to be higher in months when RPP volumes are higher (i.e., summer and winter) and lower when volumes are lower (i.e., spring and fall).
- o While there is only technically a single average RPP price (or RPA) in this report, the residential tier thresholds are higher in winter (1000 kWh) than in summer (600 kWh). This means that the average price that RPP consumers on tier prices 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.
- o 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.

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 RPP prices resulting from the forecast RPA in this report would be expected to collect slightly more than the RPP supply cost, leaving an “expected” credit of \$29 million in the variance account at the end of the RPP period, i.e. on October 31, 2017.

The OEB has determined that the RPP prices established in April 2016 will remain effective as of November 1, 2016. Given the updated cost forecast presented in this report, it is expected that the continuation of current prices will result in a debit of approximately \$11M at the end of April 30, 2017, at which time new prices will take effect. (On a 12-month basis a debit of \$66M is forecast for the end of the RPP forecast period). These residual balances are well within the range of typical variances that have been observed in the variance account over the last two years. Combined with the forecast variance account balance, current RPP prices therefore remain capable of effectively recovering the expected costs of electricity supply. The entire forecast and RPP prices will be reviewed in the spring, consistent with the OEB’s regular schedule.

The combined effect of these factors is shown in Figure 3. The values in each month of Figure 3 represent the total expected balance in the variance account at the end of each month. The values also reflect an adjustment to reflect a revision to certain non-utility generation costs.

Figure 3: Expected Monthly Variance Account Balance (\$ million)



Source: Navigant