Regulated Price Plan

Price Report

November 1, 2021

to

October 31, 2022

Ontario Energy Board

October 21, 2021

Executive Summary

This report contains the electricity commodity prices under the Regulated Price Plan (RPP) for the period November 1, 2021 through October 31, 2022. The prices were set in accordance with the methodology outlined in the Regulated Price Plan Manual (RPP Manual).

The Ontario Energy Board (OEB) is required by law to set RPP commodity prices for periods of not more than 12 months, and to set RPP prices to reflect the forecast cost of supplying RPP consumers. RPP prices are typically reviewed every six months: once in the spring (for May 1) and once in the fall (for November 1).[1]

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

1. Forecasting the RPP supply cost for 12 months, and determining the true-up to clear an appropriate portion of the supply cost variance, and
2. Establishing prices to recover the above from RPP consumers over the 12-month period.

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

- the hourly market price of electricity;
- the electricity consumption pattern of RPP consumers;
- the electricity supplied by those assets of Ontario Power Generation Inc. (OPG) whose price is regulated;
- the costs related to the contracts signed by non-utility generators (NUGs) with the former Ontario Hydro; and
- the costs of the supply contracts, and conservation and demand management (CDM) initiatives of the Independent Electricity System Operator (IESO).

The OEB has determined that the forecast RPP supply cost for the period November 1, 2021 to October 31, 2022 will not change appreciably from the RPP supply cost that underpinned the current RPP prices set on April 22, 2021 for May 1, 2021. The current RPP prices will continue to be effective in recovering the forecast costs attributable to customers on the RPP. Accordingly, no adjustments to RPP prices are required at this time.

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[1] On August 18, 2021, the Ontario government proposed regulatory amendments that, if approved, would specify that the OEB would set RPP commodity prices once per year, to take effect on November 1st of each year: https://www.ontariocanada.com/registry/view.do?postingId=38547&language=en.

Regular seasonal adjustments to time-of-use periods and residential tier threshold will still apply.

Average RPP Supply Cost

The hourly market price forecast was prepared for the OEB by Power Advisory LLC (Power Advisory). The forecast of the simple average market price for the 12 months from November 1, 2021 is $31.11/MWh (3.11 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 $33.75/MWh (3.38 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 IESO which generators have not recovered through their market revenues. The cost associated with 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 $68.78/MWh (6.88 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 supply costs during the forecast period. This "stochastic" adjustment was determined to be $1.00/MWh (or 0.10 cents per kWh) which is unchanged from the previous forecast.

An additional adjustment factor is included in the RPP price to clear the expected balance in the IESO variance account as of October 31, 2021 over the 12-month period. The expected balance, which represents a small amount owed by RPP consumers, accumulated as RPP revenues have fallen slightly below supply costs. Such variances are to be expected, as RPP costs and revenues vary from month to month, due to factors such as weather variation, fluctuations in natural gas prices, and differences in other cost inputs.

As set out in Table ES-1, the resulting average RPP supply cost (for the period starting November 1, 2021) is $103.54/MWh. This represents a change of $0.10/MWh (0.1%) from the previous RPP supply cost estimate of $103.64/MWh that was the basis for the RPP prices set by the OEB on

April 22, 2021 for May 1, 2021. This average supply cost corresponds to an average RPP price, referred to as RPA, of 10.35 cents per kWh.

Table ES-1: Average RPP Supply Cost Summary (for the period from November 1, 2021 through October 31, 2022)

RPP Supply Cost Summary for the period from November 1, 2021 through October 31, 2022		$/MWh
Forecast Wholesale Electricity Price - Simple Average		$31.11
Load-Weighted Costs for RPP Consumers		
Wholesale Electricity Cost - RPP-Weighted		$33.75
Global Adjustment	+	$68.78
Adjustment to Clear Existing Variances	+	$0.01
Adjustment to Address Bias Towards Unfavourable Variance	+	$1.00
Average Supply Cost for RPP Consumers	=	**$103.54**

Source: Power Advisory

Regulated Price Plan Prices

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: time-of-use (TOU) and tiered. RPP consumers with eligible TOU (or "smart") meters are charged on the basis of TOU prices, unless they elect instead to be charged on the basis of tiered prices by giving notice to their distributor in accordance with the OEB's Standard Supply Service Code. This customer choice option was introduced by the government for November 1, 2020. RPP consumers with conventional meters are charged on the basis of tiered prices.

Regulated Price Plan – TOU Pricing

The prices for this plan are based on three TOU periods per weekday.[2] These periods are referred to as Off-peak (with a price of $RPEM_{OFF}$), Mid-peak ($RPEM_{MID}$) and On-peak ($RPEM_{ON}$). The lowest (Off-peak) price is below the RPA, while the other two are above it. The OEB has determined that the TOU prices will not change from the previous period because they will continue to be effective in recovering forecast period RPP costs. The review of forecast costs has shown the average RPP cost for the next 12 months to be within $0.10/MWh, or approximately 0.1% of the last 12-month forecast.

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

The resulting TOU prices for consumers with eligible TOU meters which remain unchanged from those set on April 22, 2021, are the following:

- $RPEM_{OFF}$ = 8.2 cents per kWh;
- $RPEM_{MID}$ = 11.3 cents per kWh; and
- $RPEM_{ON}$ = 17.0 cents per kWh.

These prices reflect the seasonal change in the TOU pricing periods which will take effect on November 1, 2021 and May 1, 2022. TOU pricing periods are:

- *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*: 24 hours (all day)
- *Mid-peak* period (priced at $RPEM_{MID}$)
  - *Winter weekdays (November 1 to April 30)*: 11 a.m. to 5 p.m.
  - *Summer weekdays (May 1 to October 31)*: 7 a.m. to 11 a.m. and 5 p.m. to 7 p.m.
- *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, whether because they do not have an eligible TOU meter or because they have elected to pay tiered prices, 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 1,000 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 tiered prices, which remain unchanged from those set on April 22, 2021, are the following:

- $RPCM_{T1}$ = 9.8 cents per kWh, and
- $RPCM_{T2}$ = 11.5 cents per kWh.

Regulated Price Plan – Prices Effective November 1, 2021

The RPP prices set by the OEB effective November 1, 2021 are set out in Table ES-2.

Table ES-2: November 1, 2021 RPP Prices

Time-of-Use RPP Prices	Off-peak	Mid-peak	On-peak	Average Price
Price per kWh	8.2¢	11.3¢	17.0¢	10.4¢
% of TOU Consumption	64%	18%	18%	
Tiered RPP Prices	**Tier 1**		**Tier 2**	**Average Price**
Price per kWh	9.8¢		11.5¢	10.4¢
% of Tiered Consumption	65%		35%	

The government rebate under the *Ontario Rebate for Electricity Consumers Act, 2016* provides bill relief for RPP consumers, among others, in the form of a reduction in the total pre-tax amount of the bill.

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1. Introduction

Under amendments to the *Ontario Energy Board Act, 1998 (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 Ontario Regulation (O. Reg.) 95/05 (Classes of Consumers and Determination of Rates) made under the *Act*. This report covers the period from November 1, 2021 to October 31, 2022 (forecast period).

The OEB has issued a Regulated Price Plan Manual (RPP Manual[3]) that explains how RPP prices are set. The OEB relies on a forecast of wholesale electricity market prices, prepared by Power Advisory LLC (Power Advisory), 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, 2021.

This report consists of four chapters as follows:

- Chapter 1. Introduction
- Chapter 2. Calculating the RPP Supply Cost
- Chapter 3. Calculating RPP Price
- Chapter 4. Variance Accounts

1.1 Associated Documents

Two documents are closely associated with this report:

- The RPP Manual describes the methodology for setting RPP prices; and
- The *Ontario Wholesale Electricity Market Price Forecast For the Period November 1, 2021 through April 30, 2023* (Market Price Forecast Report),[4] prepared by Power Advisory, contains the Ontario wholesale electricity market price forecast and explains the material assumptions which lie behind the hourly price forecast. Those assumptions are not repeated in this report.

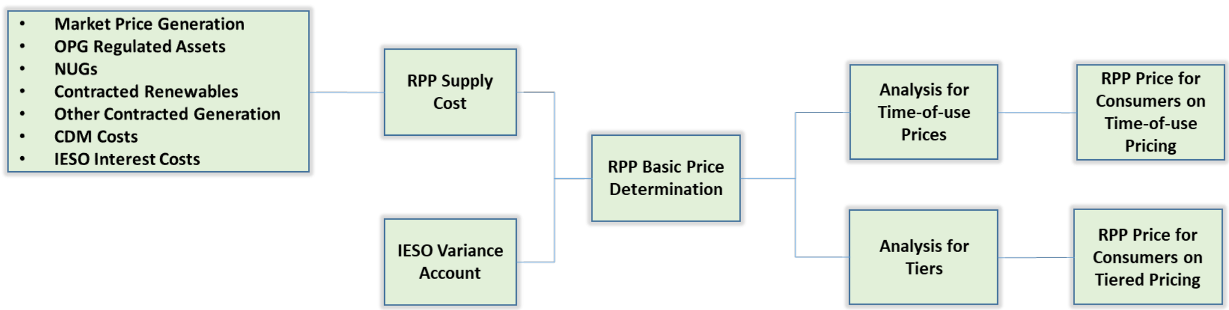
[3] https://www.oeb.ca/sites/default/files/rpp-manual-20201013.pdf

[4] https://www.oeb.ca/sites/default/files/rpp-wholesale-electricity-market-price-forecast-20211022.pdf

1.2 Process for RPP Price Determinations

Figure 1 below illustrates the processes followed to calculate RPP prices. The RPP supply cost and the accumulated variance account balance (carried by the IESO) both contribute to the base RPP price, which is set to recover the average electricity supply cost. This report is organized according to this basic process.

Figure 1: Process Flow for Determining the RPP Price



Source: RPP Manual

There are two RPP price structures: time-of-use (TOU) and tiered. RPP consumers with eligible TOU (or "smart") meters are charged on the basis of TOU prices, unless they elect instead to be charged on the basis of tiered prices by giving notice to their distributor in accordance with the OEB's Standard Supply Service Code. This customer choice option was introduced by the government for November 1, 2020 and has been implemented through rules set out the Standard Supply Service Code.[5]

[5] See subsection 6(4) of O. Reg. 95/05 and section 3.5 of the Standard Supply Service Code.

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 for the forecast period requires forecast data for the variables 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 provided 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

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

- C_{RPP} is the total 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 Global Adjustment costs;[6]

[6] The 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 Report than they are in O. Reg. 429/04 (Adjustments under Section 25.33 of the Act) made under the *Electricity Act, 1998*. "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". The Global Adjustment formula in O. Reg. 429/04 also has a component ("H") for amounts approved by the OEB under section 78.5 of the *Act* that are payable to distributors. These were amounts related to OEB-approved conservation and demand management programs under Ministerial directive. The last such program ended in 2014. As discussed below, the Global Adjustment is 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.

- A is the amount paid to prescribed generators in respect of the output of their prescribed generation facilities;[7]
- B is the amount those generators would have received under the Market Rules;
- C is the amount paid to the Ontario Electricity Finance Corporation (OEFC) with respect to its payments under contracts with non-utility generators (NUGs);
- D is the amount that would have been received under the Market Rules for electricity and ancillary services supplied by those NUGs;
- E is the amount paid to the IESO with respect to its payments under certain contracts with renewable generators;
- F is the amount that would have been received under the Market Rules for electricity and ancillary services supplied by those renewable generators;
- G is the amount paid by the IESO for its other procurement contracts for generation or for demand response or Conservation and Demand Management (CDM); and
- H is the amount associated with the variance account held by the IESO.

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 calculated 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 RPP supply cost calculation includes the Adjustment to Address Bias Towards Unfavourable Variance (the "stochastic adjustment"), which is not represented in Equation 1. The stochastic adjustment is included to take into consideration the probability that the actual RPP supply cost will be higher than the forecast, as discussed in section 2.3.

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[7] As set out in regulation O. Reg. 53/05 (Payments under Section 78.1 of the Act) made under the *Act*, the OEB sets payment amounts for energy produced from OPG's nuclear and certain hydroelectric generating stations (the prescribed assets). The OEB's most recent Order setting hydroelectric payment amounts (EB-2020-0210) was issued on December 3, 2020. Nuclear payment amounts were approved as part of EB-2016-0152 effective January 1, 2017 and for each following year through to December 31, 2021. The Decision and Order in EB-2016-0152 was issued December 28, 2017 and the Payments Amount Order was issued March 29, 2018. As described further below, OPG's application for payment amounts for the five-year period commencing in 2022 is currently before the OEB (EB-2020-0290).

As of January 1, 2019, gas-fired generation in Ontario (as well as in some other provinces) has been subject to Part II of the federal government's *Greenhouse Gas Pollution Pricing Act*, and the associated Output-Based Pricing System (OBPS) Regulations. That legislative regime introduced an OBPS, including compliance benchmarks, and prices on emissions above those benchmarks.

Effective January 1, 2022, gas-fired generation will be subject to the government of Ontario's Emissions Performance Standards (EPS).[8] This means that gas-fired generators in Ontario will transition from the OBPS system to the EPS program. The EPS program is similar to the OBPS system, including identical charges for excess emissions.

As more fully detailed in the Market Price Forecast Report, the forecast of wholesale market prices reflects the forecast of natural gas prices plus the excess emissions charges under both the OBPS (in 2021) and the EPS (in 2022) based on emission charges of $40.00/tonne of carbon dioxide equivalent (CO_2e) in 2021, and $50.00/tonne of CO_2e in 2022.

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:

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

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

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

The forecast of HOEP is taken directly from the 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 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

[8] https://www.canada.ca/en/environment-climate-change/services/climate-change/pricing-pollution-how-it-will-work/output-based-pricing-system.html

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)

Calendar Period	On-Peak	Off-Peak	Average
Nov 2021 - Jan 2022	$43.09	$25.63	$33.61
Feb 2022 - Apr 2022	$43.43	$31.87	$37.13
May 2022 - Jul 2022	$33.43	$18.54	$25.39
Aug 2022 - Oct 2022	$35.62	$22.49	$28.51
Nov 2021 - Oct 2022	**$38.86**	**$24.57**	**$31.11**

Source: Power Advisory, 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 RPP TOU pricing.

As shown in Table 1, the forecast simple average HOEP for the period November 1, 2021 to October 31, 2022 is $31.11/MWh (3.11 cents per kWh). The forecast of the load weighted average price for RPP consumers ("M" in Equation 1) is $33.75/MWh (3.38 cents per kWh), or $2.1 billion in total, the result of RPP consumers having load patterns that are more peak oriented than the overall system. The forecasts of the monthly ratios of RPP-load-weighted versus simple average HOEP are based on RPP consumption patterns between September 2016 and August 2021.[9]

2.2.2 RPP Share of the Global Adjustment

Alpha ("α") in Equation 1 represents the RPP consumers' share of the Global Adjustment. 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 the Global Adjustment is allocated to two sets of consumers, Class A and Class B (includes RPP consumers).[10]

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 is currently 17.0% for the

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[9] The OEB analysed RPP consumption profiles over the past 18 months and compared them to the previous three years to determine if COVID-19 had an appreciable impact on the typical consumption profile. Only minor differences were observed.

[10] O. Reg. 429/04 defines two classes of consumers: Class A, comprised of consumers whose maximum hourly demand for electricity exceeds a specified threshold; and Class B consumers, comprised of all other consumers, including RPP consumers. The demand threshold for Class A eligibility has been reduced over time, most recently by amendments to O. Reg. 429/04 made in 2016 (O. Reg. 366/16) and 2017 (O. Reg. 107/17).

July 2021 to June 2022 period.[11] Power Advisory forecasts that beginning July 2022, the Class A share of Global Adjustment charges will fall slightly to 16.7%, due to demand management measures anticipated to be taken by Class A consumers.

Class B's share of the Global Adjustment is forecast to be 83.1% over the forecast period.

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 amount to approximately 62 TWh, or 63% of total Class B consumption. The RPP share varies with the seasons, ranging between 61% and 66%. RPP consumers' share of monthly Global Adjustment charges ranges between 50% and 55%. Over the entire forecast period, the RPP consumers' share of the Global Adjustment is forecast to be 52.6%. The value of α is therefore 0.526.

2.2.3 Cost Adjustment Term for Prescribed Generators

This section covers the second term of Equation 1:

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

Quantity A is the amount paid for the output of the prescribed rate-regulated nuclear and hydroelectric facilities of Ontario Power Generation Inc. (OPG) based on payment amounts set by the OEB. The 2021 payment amounts for OPG's prescribed generation are $95.83/MWh for nuclear generation, and $45.93/MWh for hydroelectric generation. These payment amounts, which reflect both base payment amounts and rate riders, were set out in the following two OEB decisions: EB-2016-0152 and EB-2020-0210.

On December 31, 2020, OPG filed an application (EB-2020-0290) seeking approval for payment amounts for its prescribed generation facilities commencing January 1, 2022 through to the end of 2026. Consistent with past practice, the OEB has determined that it is appropriate to take this application into account in this RPP supply cost forecast given its advanced status, as described below.

On July 16, 2021, OPG filed a settlement proposal for the OEB's consideration. The proposal indicated that parties had reached settlement on most issues but not including: (i) OPG's request for approval to recover 100% of its Heavy Water Storage and Drum Handling Facility

[11] "Class A customers are assessed their portion of GA costs based on the percentage that their consumption contributes to the top five system coincident peaks during a predetermined base period (May 1-April 30) and will be charged their percentage of total GA costs through the next adjustment, or billing period (July 1-June 30)." (http://www.ieso.ca/en/Sector-Participants/Settlements/Global-Adjustment-and-Peak-Demand-Factor)

project costs (D2O Project), or (ii) OPG's rate smoothing proposal. The OEB approved the settlement proposal orally on August 6, 2021, with written reasons to follow. A final Decision and Order on the D2O Project costs is pending, and the OEB has indicated that it will address OPG's rate smoothing proposal after its Decision and Order is issued.

Given the advanced status of the application, the OEB has determined that the RPP supply cost forecast should reflect the nuclear and hydroelectric base payment amounts and rate riders included in the settlement proposal, without adjustment for the rate smoothing proposal. Regarding the D2O Project, OPG's application seeks approval to recover $510 million in project costs.[12] As this issue was not settled, the OEB has determined that the RPP supply cost forecast should reflect 50% of that total cost of the D2O Project; namely, $255 million. The inclusion of this amount in the supply cost forecast should in no way be taken as predictive of the outcome of the current OPG proceeding.

Quantity A was therefore forecast by multiplying per-MWh payment amounts provided at Table 3 found at Appendix B, page 56 of the settlement proposal, with the nuclear payment amounts adjusted for the factors described above, by the prescribed assets' total forecast output per month in MWh.

Quantity B (the dollar amount that the prescribed generators would receive under the Market Rules) was forecast by estimating the market values of each MWh of nuclear and prescribed hydroelectric generation, and multiplying those market values by the volume of nuclear and prescribed hydroelectric generation. The value of A is $5.33 billion, and the value of B is $2.39 billion.

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

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

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

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

[12] OPG 2022-2026 Payment Amounts Application: Exhibit D2, Tab 2, Schedule 10 , p. 1. The total cost of the D2O Project is $510 million, consisting of $509.3 million in capital and $0.7 million in OM&A for removal costs incurred in 2013. Of the $509.3 million in capital cost, $14.6 million placed in service in 2014 has already been approved for inclusion in rate base. OPG seeks approval to incorporate the remaining $494.7 million capital cost into rate base in its 2022-2026 Payment Amounts application.

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 $0.06 billion, and the value of "D" (i.e., the market value of the NUG output) is estimated to be $0.02 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:

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

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:

- Renewable Energy Supply (RES) Request for Proposals (RFP) Phases I, II and III;
- the Renewable Energy Standard Offer Program (RESOP);
- the Feed-In Tariff (FIT) Program;
- the Hydroelectric Standard Offer Program (HESOP);
- the Hydroelectric Energy Supply Agreements (HESA) directive, covering new and redeveloped hydro facilities;
- the Hydro Contract Initiative (HCI), covering existing hydro plants;
- the Energy from Waste program; and
- NUGs who are under contract with the IESO rather than OEFC.

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).[13]

The size and generation type of the successful renewable energy projects to-date have been announced by the government of Ontario and the IESO. The forecast includes additional

[13] For information related to the FIT Price Schedule, see the IESO's dedicated web page at: http://www.ieso.ca/sector-participants/feed-in-tariff-program/overview

renewable capacity coming into service during the forecast 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 forecast also considers 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 Market Price Forecast Report) at the time that output is generated.

On December 15, 2020, the Government of Ontario announced that if will be funding a portion of the Global Adjustment associated with specified non-hydro renewable contracts directly, and that these costs would therefore be removed from the GA. As specified in a letter dated December 15, 2020, the government funding amount will total $3.12 billion over the November 1, 2021 to October 31, 2022 RPP period.[14] Net of this amount, the value of "E" in Equation 1 (i.e., the contract cost of renewable generation covered by the GA) is estimated to be $1.96 billion, and the value of "F" (i.e., the market value of renewable generation) is estimated to be $0.76 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:

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

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. Conservation and demand management costs, and storage 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:

- Clean Energy Supply (CES) and other contracts, which include conventional gas generation contracts as well as one demand response contract;
- The "early mover", "Accelerated CES" and "Northern York Region" contracts; and
- Contracts awarded for gas-fired projects classified as Combined Heat and Power (CHP) projects.

[14] https://www.oeb.ca/sites/default/files/letter-from-the-Minister-ENDM-20201215.pdf

The costs of these generation 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 Market Price Forecast Report that underpins this report. 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 of Ontario to be $7,900 per megawatt-month,[15] as well as an NRR of $17,000 per megawatt-month for the cancelled Oakville Generating Station which has been used as a guideline for some of the more recent gas plant additions.

The cost of CDM initiatives delivered under contract with the IESO is also captured in term G of Equation 1. On September 30, 2020, the IESO was directed to establish and deliver a new 2021-2024 CDM Framework under which the IESO will centrally deliver CDM programs using procurement contracts as required.[16] The forecast of CDM initiative costs for the forecast period reflects the cost implications of the 2021-2024 CDM Framework.

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 units. 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 every April 1, as well as adjusted periodically for asset management, waste fees, and refurbishments. For this forecast 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 (Lennox), a 2,140-MW gas-fired peaking plant. The cost of this contract is included in the "G" variable. This contract is due to expire on September 30, 2022, before the last month of the forecast period (October 2022). The IESO's September 23, 2021 Reliability Outlook Report indicates that the IESO and OPG are engaged in bilateral negotiations on a contract extension.[17] Although the outcome of those negotiations is not known at this time, the RPP supply cost forecast assumes that, throughout the forecast period, Lennox will be in service and will receive

[15] The NRR for the "early movers" was assumed to be the same.

[16] https://www.ieso.ca/en/Corporate-IESO/Ministerial-Directives/2021-2024-Conservation-and-Demand-Management-Framework

[17] https://www.ieso.ca/-/media/Files/IESO/Document-Library/planning-forecasts/reliability-outlook/ReliabilityOutlook2021Sep.ashx

payments for its supply in amounts that reflect its current contract terms in the month of October 2022.

The value of "G" in Equation 1 (i.e., net cost of Bruce Power nuclear, gas, CDM costs and storage contracts) is estimated to be $3.88 billion.

2.2.7 Estimate of the Global Adjustment

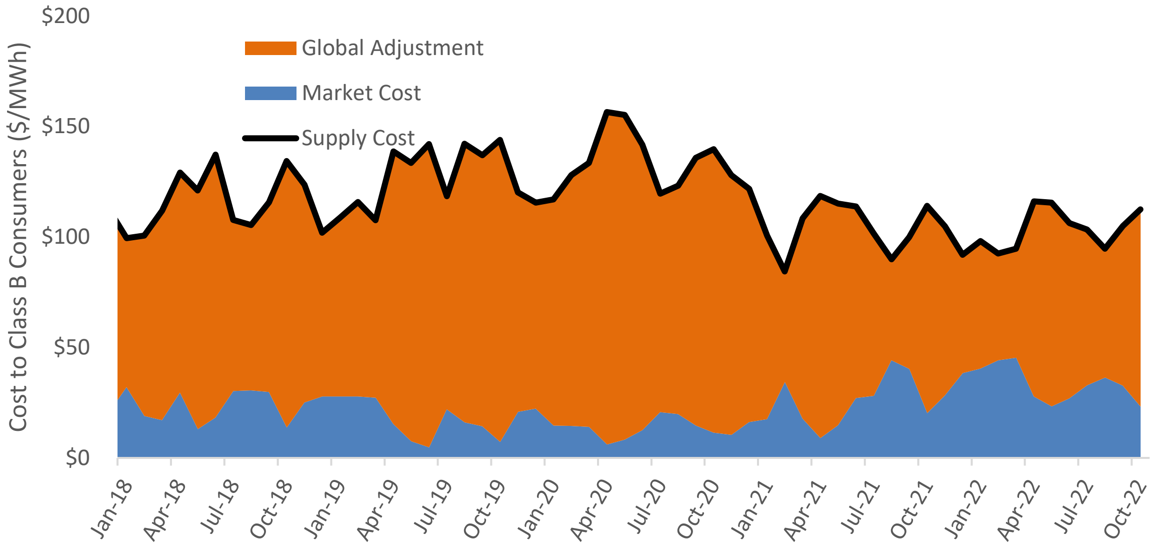
The total Global Adjustment cost is estimated to be $8.2 billion. The RPP share of this (i.e., α times the total cost) is estimated to be $4.3 billion, or $68.78/MWh (6.88 cents per kWh). This is the forecast of the average Global Adjustment cost per unit for RPP consumers over the period from November 1, 2021 to October 31, 2022. The RPP share of the total Global Adjustment is affected by changes in the share of the Global Adjustment costs paid by Class A and Class B consumers, as well as changes in the volume of Class B consumption.

The Global Adjustment represents the difference between the total contract cost of the various contracts it covers (for Bruce Power nuclear, gas plants, renewable generation, CDM, etc.) and the market value of contracted generation, as well as the difference between the payment amounts set for OPG's prescribed generating assets and the market value of that generation. Total Global Adjustment costs can therefore change for three reasons:

- changes (mostly increases) in the number and aggregate capacity of contracts or rate-regulated assets it covers;
- changes in regulated rates or inflation-based adjustments in contract rates; and
- fluctuations in the market revenues earned by contracted and prescribed generation.

This is illustrated in Figure 2, which shows how the Global Adjustment has changed over the past 4 years, and is expected to change over the next 12 months.

Figure 2: Components of the RPP Supply Cost



Source: Power Advisory

The forecast average supply cost for RPP consumers decreases by 0.1% in the current forecast compared to the previous RPP supply cost forecast (April 2021).[18] This small change is the net result of two larger changes. The first is that the forecast RPP-weighted HOEP has increased by $14.50/MWh (1.45¢/kWh), primarily due to a large increase in natural gas forward prices. The second is that forecast Global Adjustment charges have decreased by $16.40 (1.64¢/kWh), primarily due to the increase in HOEP, and how GA charges are split between Class A and Class B consumers. When HOEP increases, generators' wholesale market revenues increase, and they receive lower out-of-market payments funded through the GA. Class B consumers, including RPP customers, pay most (approximately 83%) of GA charges, so the decrease in GA charges more than offsets the increase in HOEP. A small part of the GA decrease is offset by increases in underlying costs, including the contract and regulated rates for nuclear and regulated hydroelectric generation.

2.2.8 Cost Adjustment Term for and Recovery Related to IESO Variance Account

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

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

For the purposes of setting RPP prices, two aspects of the IESO's variance account are considered. The first is the forecast interest costs associated with carrying any RPP-related variances incurred during the upcoming RPP period (November 2021 – October 2022). The second represents the

[18] Regulated Price Plan Price Report, April 22, 2021: https://www.oeb.ca/sites/default/files/rpp-price-report-20210422.pdf

price adjustment required to clear (i.e., recover or disburse) an appropriate portion of the RPP variance and accumulated interest.

The first aspect 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 forecast net interest earned for this price setting period is approximately $0.1 million – i.e., interest income is expected to be almost offset by interest expenses.

The second aspect represents the price adjustment to reduce the variance accumulated through to the beginning of this RPP period. As of August 31, 2021, the net variance account balance was a surplus of $39 million, but it is expected to be a deficit of $0.5 million by October 31, 2021, due to differences between current rates and forecast RPP supply costs in September and October 2021. The forecast adjustment factor has been set with a view to clearing the existing variance balance over 12 months, and is a small charge (increase in the RPP price) of $0.01/MWh (or 0.001¢ per kWh).

2.3 Correcting for the Bias Towards Unfavourable Variances (Stochastic Adjustment)

The supply costs discussed in section 2.2 are based on “most likely” forecasts of demand, HOEP, gas prices, generator operations, and other factors. However, none of these factors can 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 it is more likely that RPP supply costs will exceed the forecast than fall below it, unless there is a minor adjustment to reflect the greater likelihood of unfavourable variances.

The Adjustment to Address Bias Towards Unfavourable Variance (stochastic adjustment) is set at $1.00/MWh (0.10 cents per kWh). This amount is included in the RPP supply cost.

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 or regulated payment amounts for each generation type, including Global Adjustment payments and market price payments, where applicable. The amounts have not been adjusted for the government funding amounts for specified non-hydro renewable contracts described in section 2.2.5.

Table 2: Total Electricity Supply Cost

	% of Total Supply	% of Total Global Adjustment	Total Unit Cost (cents/kWh)
Nuclear	51%	47%	9.6¢
Hydro	27%	9%	5.8¢
Gas	10%	11%	12.5¢
Wind	9%	16%	15.4¢
Solar	2%	15%	49.8¢
Bioenergy	1%	2%	26.7¢

Source: Power Advisory

NB: Percentage (%) of Total Global Adjustment excludes CDM costs.

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

The following table itemizes the various steps discussed above to arrive at an average RPP supply cost of $103.54/MWh. This average supply cost corresponds to an average RPP price, which is referred to as RPA, of 10.35 cents per kWh.

Table 3: Average RPP Supply Cost Summary

RPP Supply Cost Summary for the period from November 1, 2021 through October 31, 2022		$/MWh
Forecast Wholesale Electricity Price - Simple Average		$31.11
Load-Weighted Costs for RPP Consumers		
Wholesale Electricity Cost - RPP-Weighted		$33.75
Global Adjustment	+	$68.78
Adjustment to Clear Existing Variances	+	$0.01
Adjustment to Address Bias Towards Unfavourable Variance	+	$1.00
Average Supply Cost for RPP Consumers	=	**$103.54**

Source: Power Advisory

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 RPA. This chapter explains how prices are determined for consumers 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 TOU Prices

For those consumers with eligible TOU (or "smart") meters and that have not elected tiered pricing, prices are calculated for three separate price periods: On-peak ($RPEM_{ON}$), Mid-peak ($RPEM_{MID}$), and Off-peak ($RPEM_{OFF}$). The times when each of these periods applies are set out in the RPP Manual and also noted below. 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 RPA, given the load shape of TOU customers. The RPP Manual does not prescribe the order in which prices are calculated. Generally, when setting prices, consideration is given to both the current ratios between $RPEM_{ON}$, PEM_{MID} and $RPEM_{OFF}$, and how the various components of Global Adjustment costs are allocated to TOU consumption periods based on the type of cost.

The various components of Global Adjustment costs are first allocated to TOU consumption periods based on the type of cost. The costs associated with OPG's rate-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 Global Adjustment 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 adjustment to clear the IESO variance account is allocated equally to all consumption periods. The overall effect of this allocation is that the differential between the On-peak and Off-peak prices is 2:1.

The ratios developed for the November 1, 2021 price setting are consistent with the ratios generated through the cost allocation exercise and the current ratio between On-, Off-, and Mid-peak prices, and maintains the strong incentive for electricity consumers to shift their consumption away from On-peak periods, when their electricity prices are highest.

The review of RPP supply costs has shown the average RPP cost for the next 12 months to be within 0.1% of the last 12-month forecast. The OEB has determined that the current TOU prices will continue to be effective in recovering the forecast costs.

The calculated TOU prices are not materiality different from the current RPP prices, therefore no change is being made. The prices remain as follows:

- $RPEM_{OFF}$ = 8.2 cents per kWh
- $RPEM_{MID}$ = 11.3 cents per kWh, and
- $RPEM_{ON}$ = 17.0 cents per kWh.

These prices reflect the seasonal change in the TOU pricing periods which will take effect on November 1, 2021 and May 1, 2022. As defined in the RPP Manual, the time periods for TOU price application are as follows:

- *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*[19]: 24 hours (all day)
- *Mid-peak* period (priced at $RPEM_{MID}$)
  - *Winter weekdays (November 1 to April 30)*: 11 a.m. to 5 p.m.
  - *Summer weekdays (May 1 to October 31)*: 7 a.m. to 11 a.m. and 5 p.m. to 7 p.m.
- *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.

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

The load profile assumed for TOU consumers was calculated based on TOU consumers' actual Off-, Mid-, and On-peak consumption observed over the previous four years. The load profile for non-TOU RPP (tiered) consumers was determined using the methodology described in section 3.2.

[19] For the purpose of RPP TOU 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 TOU pricing purposes.

RPP prices are calculated so that a TOU consumer with an average TOU load profile would 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. Note that RPP consumers generally (i.e., both tier and TOU RPP consumers) have load profiles that are more peak-oriented than the overall system.

3.2 Tiered Prices

The final step is to calculate tiered prices, which apply to RPP consumers with conventional meters and to RPP consumers with eligible TOU (or "smart") meters that have elected to pay tiered pricing. 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.

RPP consumers with eligible TOU (or "smart") meters may now elect instead to be charged on the basis of tiered prices by giving notice to their distributor in accordance with the OEB's Standard Supply Service Code. This customer choice option was introduced by the government for November 1, 2020, and has been implemented through rules set out the Standard Supply Service Code.[20]

Once the RPP Supply Cost has been determined, the next step in setting tier prices is to forecast the expected ratio of consumption between the lower ($RPCM_{T1}$) and higher tier price ($RPCM_{T2}$). Based on historical data (which show a shift in recent months from the higher to the lower tier), the OEB forecasts the ratio to be 65% $RPCM_{T1}$ and 35% $RPCM_{T2}$ over the RPP period.

RPP tiered prices are calculated 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 0.85 ratio between Tier 1 and Tier 2 prices.

The calculated tiered prices are not materially different from the current tiered prices, therefore no change is being made. The prices remain as follows:

- $RPCM_{T1}$ = 9.8 cents per kWh; and
- $RPCM_{T2}$ = 11.5 cents per kWh.

[20] See subsection 6(4) of O. Reg. 95/05 and section 3.5 of the Standard Supply Service Code.

3.3 Regulated Price Plan Prices Effective November 1, 2021

Table 4 below summarizes the RPP TOU and tiered prices effective November 1, 2021.

Table 4: November 1, 2021 RPP Prices

Time-of-Use RPP Prices	Off-peak	Mid-peak	On-peak	Average Price
Price per kWh	8.2¢	11.3¢	17.0¢	10.4¢
% of TOU Consumption	64%	18%	18%	
Tiered RPP Prices	**Tier 1**		**Tier 2**	**Average Price**
Price per kWh	9.8¢		11.5¢	10.4¢
% of Tiered Consumption	65%		35%	

4. Variance Accounts

There are two sources of variances: cumulative under- or over-collection due to discrepancies in forecast versus actual supply costs (referred to as the "unexpected variance" in the RPP Manual) and those created by predictable seasonal variances (referred to as the "expected variance" in the RPP Manual). The cumulative discrepancy represents the price adjustment necessary to clear the total balance in the IESO variance account accumulated through to the beginning of this RPP period. As of August 31, 2021, the cumulative discrepancy was a surplus of $39 million, but it is expected to be a surplus of $0.5 million by October 31, 2021, due to differences between current rates and forecast supply costs in September and October 2021.

The variance caused by seasonal variation represents the amount of money customers are expected to over- or underpay for the electricity they consume in a given month. The balance in the variance account varies significantly from month-to-month for several reasons:

- Variance clearance will tend to be higher in months when RPP volumes are higher (i.e., summer and winter) and lower when volumes are lower (i.e., spring and fall).
- While there is only technically a single RPA in this report, the residential tier thresholds are normally higher in winter (1,000 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.
- 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.

RPP prices are set with a view to achieving a balance of zero for the variance balance associated with seasonal variation at the end of the RPP period.

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 IESO variance account at the end of each month.

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