Regulated Price Plan

Price Report

November 1, 2023

to

October 31, 2024

Ontario Energy Board

October 19, 2023

Executive Summary

This report contains the electricity commodity prices under the Regulated Price Plan (RPP) for the period November 1, 2023 through October 31, 2024. 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 every year, to take effect on November 1 of each year, and to set RPP prices to reflect the forecast cost of supplying RPP consumers.

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).

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, 2023 is $29.38/MWh (2.94 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 $31.80/MWh (3.18 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 that 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 $72.86/MWh (7.29 cents per kWh).

Another factor to be considered 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, 2023 over the 12-month period. The expected balance, which represents an amount owed by RPP consumers, accumulated as RPP revenue shortfalls over the past 12 months, is forecast to be $342 million. 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 forecast for the period starting November 1, 2023 is $111.05/MWh. This represents an increase of $17.65/MWh (19%) from the previous RPP supply cost estimate of $93.40/MWh that was the basis for the RPP prices set by the OEB on October 21, 2022 for November 1, 2022. This average supply cost corresponds to an average RPP price, referred to as RPA, of 11.11 cents per kWh.

Table ES-1: Average RPP Supply Cost Forecast Summary
(November 1, 2023 to October 31, 2024)

RPP Supply Cost Summary for the period from November 1, 2023 through October 31, 2024		$/MWh
Forecast Wholesale Electricity Price - Simple Average		$29.38
Load-Weighted Costs for RPP Consumers		
Wholesale Electricity Cost - RPP-Weighted		$31.79
Global Adjustment	+	$72.86
Adjustment to Clear Existing Variances	+	$5.40
Adjustment to Address Bias Towards Unfavourable Variance	+	$1.00
Average Supply Cost for RPP Consumers	=	**$111.05**

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 three RPP price structures: time-of-use (TOU), ultra-low overnight (ULO), and tiered. RPP consumers with eligible TOU (or "smart") meters are charged on the basis of TOU prices, unless they elect one of the other options by giving notice to their distributor in accordance with the OEB's Standard Supply Service Code. 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.[1] These periods are referred to as Off-peak (with a price of $RPEM_{OFF}$), Mid-peak ($RPEM_{MID}$) and On-peak ($RPEM_{ON}$). The lowest (Off-peak) price is below the RPA, while the other two are above it.

The resulting TOU prices for consumers with eligible TOU meters are:

- $RPEM_{OFF}$ = 8.7 cents per kWh;
- $RPEM_{MID}$ = 12.2 cents per kWh; and
- $RPEM_{ON}$ = 18.2 cents per kWh.

These prices reflect the seasonal change in the TOU pricing periods which will take effect on November 1, 2023 and May 1, 2024. 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.

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

Regulated Price Plan – ULO Pricing

RPP customers who have eligible TOU meters may elect to be charged on the basis of ULO prices. The four ULO periods are:

- *Overnight* period (priced at ULO_{NIGHT}):
  - *Every day*: 11 p.m. to 7 a.m.
- *Off-peak* period (priced at ULO_{OFF}):
  - *Weekends and holidays*: 7 a.m. to 11 p.m.
- *Mid-peak* period (priced at ULO_{MID})
  - *Weekdays*: 7 a.m. to 4 p.m. and 9 p.m. to 11 p.m.
- *On-peak* period (priced at ULO_{ON})
  - *Weekdays*: 4 p.m. to 9 p.m.

The ULO prices effective November 1, 2023 are:

- ULO_{NIGHT} = 2.8 cents per kWh;
- ULO_{OFF} = 8.7 cents per kWh;
- ULO_{MID} = 12.2 cents per kWh; and
- ULO_{ON} = 28.6 cents per kWh.

Regulated Price Plan - Tiered Pricing

RPP consumers who are not on TOU or ULO 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 ($RPCM_{T1}$) for monthly consumption up to a tier threshold, and a higher price ($RPCM_{T2}$) 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 are:

- $RPCM_{T1}$ = 10.3 cents per kWh, and
- $RPCM_{T2}$ = 12.5 cents per kWh.

Regulated Price Plan – Prices Effective November 1, 2023

The RPP prices set by the OEB effective November 1, 2023 are set out in Table ES-2.

Table ES-2: November 1, 2023 RPP Prices[2]

Standard TOU Prices	Off-peak		Mid-peak		On-peak		Average Price
Price per kWh	8.7¢		12.2¢		18.2¢		11.1¢
% of TOU Consumption	63%		18%		19%		
ULO Prices	**Overnight**	**Weekend**	**Mid-peak**	**On-peak**			**Average Price**
Price per kWh	2.8¢	8.7¢	12.2¢	28.6¢			11.1¢
% of ULO Consumption	33%	20%	31%	16%			
Tiered Prices	**Tier 1**			**Tier 2**			**Average Price**
Price per kWh	10.3¢			12.5¢			11.1¢
% of Tiered Consumption	63%			37%			

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.

Major Factors Causing the Change in Average RPP Supply Cost

The forecast average supply cost for RPP consumers increases by 19% in the current forecast compared to the previous RPP supply cost forecast (October 2023). The increase is mainly attributable to:

1. An increase in Global Adjustment payments to nuclear and natural gas generators; and
2. The projected $342 million deficit in the IESO variance account being recovered from RPP consumers over the RPP period. This deficit is due to higher-than-forecast supply cost over the previous RPP period. This led to under-collection from RPP consumers in the November 2022 to October 2023 period.

[2] Values in Table ES-2 may not result in the exact Average Price due to rounding

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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, 2023 to October 31, 2024 (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, 2023.

This report consists of four chapters as follows:

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

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, 2023 through April 30, 2025* (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.

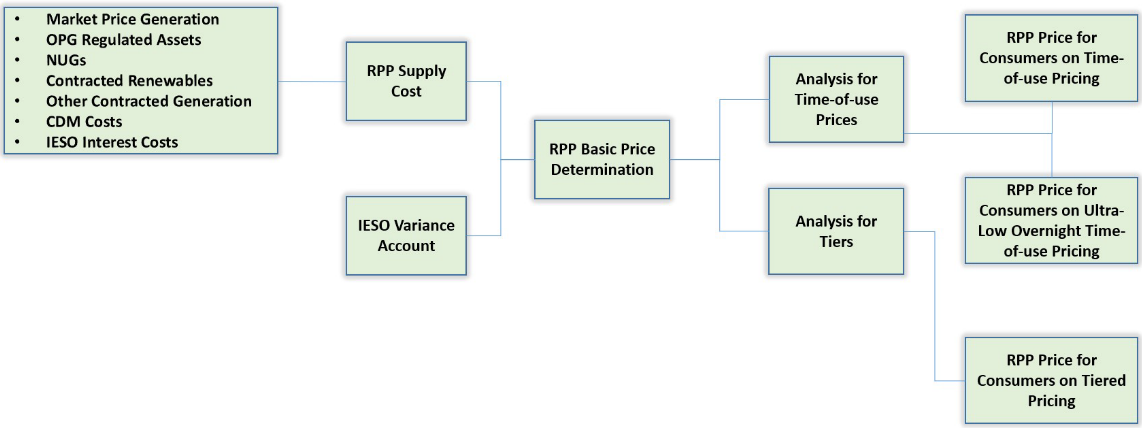
[3] https://www.oeb.ca/sites/default/files/rpp-manual-20231019.pdf

[4] https://www.oeb.ca/sites/default/files/rpp-wholesale-electricity-market-price-forecast-20231019.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 three RPP price structures: time-of-use (TOU), ultra-low overnight (ULO), 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 for one of the other options by giving notice to their distributor in accordance with the OEB's Standard Supply Service Code. RPP consumers with conventional meters are charged on the basis of tiered prices.

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;[5]
- A is the amount paid to prescribed generators in respect of the output of their prescribed generation facilities;[6]

[5] 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.

[6] 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). Nuclear and hydroelectric payment amounts were approved as part of the EB-2020-0290 proceeding effective January 1, 2022 and for each following year through to December 31, 2026. The Decision and Order for this proceeding was issued November 15, 2021 and the Payments Amount Order was issued January 27, 2022.

- 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.

Beginning January 1, 2022, gas-fired generation has been subject to the government of Ontario's Emissions Performance Standards (EPS).[7] The EPS includes compliance benchmarks, and prices on emissions above those benchmarks.

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 the EPS based on emission charges of $65.00/tonne of carbon dioxide equivalent (CO_2e) in 2023, and $80.00/tonne of CO_2e in 2024.

[7] Emissions Performance Standards program | ontario.ca

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 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 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 2023 - Jan 2024	$36.89	$25.00	$30.44
Feb 2024 - Apr 2024	$38.00	$28.55	$32.89
May 2024 - Jul 2024	$30.18	$17.95	$23.59
Aug 2024 - Oct 2024	$37.06	$25.38	$30.70
Nov 2023 - Oct 2024	**$35.52**	**$24.20**	**$29.38**

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, 2023 to October 31, 2024 is $29.38/MWh (2.94 cents per kWh). The forecast of the load-weighted average price for RPP consumers ("M" in Equation 1) is $31.79/MWh (3.18 cents per kWh), or $2.05 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 2018 and August 2023.

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* revised how the Global Adjustment is allocated to two sets of consumers, Class A and Class B (includes RPP consumers).[8]

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 approximately 16.5% for the July 2023 to June 2024 period.[9] Power Advisory forecasts that the Class A share of Global Adjustment charges will remain at approximately the same level (16.5%) for the July 2024 to June 2025 period, which includes the last four months of the RPP period. Power Advisory's forecast is based on actual ratios in previous years and demand management measures anticipated to be taken by Class A consumers.

Class B's share of the Global Adjustment is forecast to be 83.5% 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 64 TWh, or 64% of total Class B consumption. The RPP share varies with the seasons, ranging between 62% and 66%. RPP consumers' share of monthly Global Adjustment charges ranges between 52% and 55%. Over the entire forecast period, the RPP consumers' share of the Global Adjustment is forecast to be 53.2%. The value of $\boldsymbol{\alpha}$ is therefore 0.532.

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[8] 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).

[9] "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)

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 payment amounts for OPG's prescribed generation in 2023 are $109.04/MWh for nuclear generation, and $44.91/MWh for hydroelectric generation, and in 2024 are $104.63/MWh for nuclear generation, and $44.91/MWh for hydroelectric generation. These payment amounts, which reflect both base payment amounts and rate riders, were set out in the OEB decision in the EB-2020-0290 proceeding.

Quantity A was therefore forecast by multiplying payment amounts per MWh 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 hydroelectric generation, and multiplying those market values by the volume of nuclear and prescribed hydroelectric generation. The value of A is $5.20 billion, and the value of B is $2.03 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.

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).[10]

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 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

[10] 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

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 it will be funding a portion of the Global Adjustment associated with specified non-hydro renewable contracts directly under its Comprehensive Electricity Plan, and that these costs would therefore be removed from the GA. As specified in a letter dated April 3, 2023, the government funding amount will total $3.19 billion over the November 1, 2023 to October 31, 2024 RPP period.[11] 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 $2.05 billion, and the value of "F" (i.e., the market value of renewable generation) is estimated to be $0.94 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.

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)

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[11] https://www.ieso.ca/-/media/Files/IESO/Document-Library/corporate/ministerial-directives/Letter-from-the-Minister-of-Energy-20230403-Comprehensive-Electricity-Plan.ashx

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,[12] 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.[13] Further, on September 30, 2022, the 2021-2024 CDM Framework directive was amended to increase program budgets.[14] The forecast of CDM initiative costs for the forecast period reflects the cost implications of the amended 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 contract came into effect on October 1, 2022, after the previous contract expired, and runs through May 1, 2029. The cost of this contract is included in the "G" variable.

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 $4.52 billion.

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

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

[14] https://www.ieso.ca/-/media/Files/IESO/Document-Library/corporate/ministerial-directives/Directive-from-the-Minister-of-Energy-20221004-Expansion-CDM-Framework.ashx

2.2.7 Estimate of the Global Adjustment

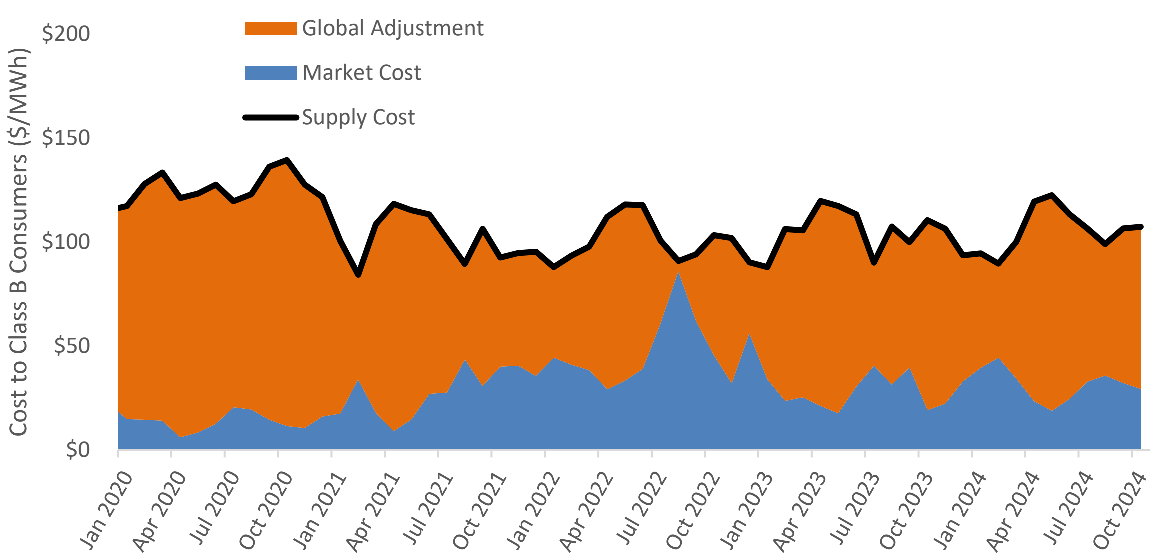
The total Global Adjustment cost is estimated to be $8.83 billion. The RPP share of this (i.e., α times the total cost) is estimated to be $4.70 billion, or $72.86/MWh (7.29 cents per kWh). This is the forecast of the average Global Adjustment cost for RPP consumers over the period from November 1, 2023 to October 31, 2024. 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 several items. First, 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. Second, 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

Prior to adjusting for the balance in the IESO variance account (term H) and the stochastic adjustment, the forecast average supply cost for RPP consumers increases by 7% in the current forecast compared to the previous RPP supply cost forecast (November 2022).[15] This change is the net result of two larger, interacting, changes. The first is that the forecast RPP-weighted HOEP has decreased by $26.53/MWh (2.65 cents per kWh), primarily due to a decrease in natural gas forward prices. The second is that forecast Global Adjustment charges have increased by $33.82 (3.38 cents per kWh). Global Adjustment increases with decreased HOEP due to the increased out-of-market payments it funds. These out-of-market payments relate to the underlying costs of supply that generators do not recover from the wholesale electricity market, as described above as components of Equation 1. Additionally, Class B consumers, including RPP customers, pay most (approximately 83%) of Global Adjustment charges, so increases in Global Adjustment is mildly amplified for RPP Customers.

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 2023 – October 2024). The second represents the 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 the interest rate paid by the IESO on the variance account is relatively low. The forecast net interest charged for this price setting period is approximately $6 million.

The second aspect represents the price adjustment to reduce the variance accumulated through to the beginning of this RPP period. As of August 31, 2023, the net variance account balance was a deficit of less than $100 million. This deficit is expected to increase to $342 million by October 31, 2023. The forecast adjustment factor has been set with a view to clearing that variance account balance over 12 months, and is an additional charge (increase in the RPP price) of $5.40/MWh (or 0.54 cents 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 such as demand. However, none of these

[15] Regulated Price Plan Price Report, October 2022: https://www.oeb.ca/sites/default/files/rpp-price-report-20221021.pdf

factors can be predicted with absolute certainty. Calculating the total RPP supply cost therefore needs to take into account the inherent volatility within the forecast parameters, resulting in 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¢ 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 Comprehensive Electricity Plan funding amounts described in section 2.2.5.

Table 2: Electricity Unit Cost Forecast

	% of Total Supply	% of Total Global Adjustment	Total Unit Cost (cents/kWh)
Nuclear	50%	48%	10.1¢
Hydro	26%	10%	6.2¢
Gas	12%	11%	11.4¢
Wind	9%	15%	14.7¢
Solar	2%	14%	47.4¢
Bioenergy	1%	2%	26.8¢

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

After taking the Comprehensive Electricity Plan funding amounts into account, the values of each term in Equation 1 are:

$$C_{RPP} = \$2.05 \text{ billion} + 0.532 * [(\$5.20 \text{ billion} - \$2.03 \text{ billion}) + (\$0.06 \text{ billion} - \$0.02 \text{ billion}) + (\$2.05 \text{ billion} - \$0.94 \text{ billion}) + \$4.52 \text{ billion}] + \$0.35 \text{ billion} = \$7.10 \text{ billion}$$

The Adjustment to Address Bias Towards Unfavourable Variance ($1/MWh x 64 TWh = $0.06 billion) is added to this, to give a total RPP supply cost of $7.16 billion.

The following table itemizes the various steps discussed above to arrive at an average RPP supply cost of $111.05/MWh. This average supply cost corresponds to an average RPP price, which is referred to as RPA, of 11.11 cents per kWh.

Table 3: Average RPP Supply Cost Forecast Summary

RPP Supply Cost Summary for the period from November 1, 2023 through October 31, 2024			$/MWh
Forecast Wholesale Electricity Price - Simple Average			$29.38
Load-Weighted Costs for RPP Consumers			
	Wholesale Electricity Cost - RPP-Weighted		$31.79
	Global Adjustment	+	$72.86
	Adjustment to Clear Existing Variances	+	$5.40
	Adjustment to Address Bias Towards Unfavourable Variance	+	$1.00
Average Supply Cost for RPP Consumers		=	**$111.05**

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, referred to as the RPA. This chapter explains how prices are determined for consumers under the different price plan options.

3.1 TOU Prices

For those consumers with eligible TOU (or "smart") meters and who have not elected tiered or ULO 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 ratios developed for the November 1, 2023 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 maintain the strong incentive for electricity consumers to shift their consumption away from On-peak periods, when their electricity prices are highest.

The resulting TOU prices are:

- $RPEM_{OFF}$ = 8.7 cents per kWh
- $RPEM_{MID}$ = 12.2 cents per kWh, and
- $RPEM_{ON}$ = 18.2 cents per kWh

These prices reflect the seasonal change in the TOU pricing periods which will take effect on November 1, 2023 and May 1, 2024. 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*[16]: 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 ULO and tiered consumers was determined using the methodology described in sections 3.2 and 3.3, respectively.

RPP prices are calculated so that a typical TOU consumer with an average TOU load profile would pay the same average price as a typical ULO or Tiered RPP consumer under those respective options. This average price is equal to the RPA. Note that RPP consumers generally have load profiles that are more peak-oriented than the overall system.

[16] For the purpose of RPP TOU pricing, a "holiday" means the following days: New Year's Day, Family Day, Good Friday, Victoria Day, Canada Day, the Civic Holiday, Labour Day, Thanksgiving Day, Christmas Day, and Boxing Day. 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.

3.2 ULO Prices

Beginning November 1, 2023, all electricity distributors are required to offer RPP consumers with a smart meter the option of enrolling in the ULO price plan. Some distributors made this new option available earlier (as early as May 1, 2023 in some cases). The OEB set ULO prices for the first time on April 11, 2023, for the period May 1, 2023 to October 31, 2023, by way of an Addendum to the RPP Price Report for November 1, 2022 to October 31, 2023.

ULO prices are calculated for four price periods: These periods are referred to as Ultra-low Overnight (ULO_{NIGHT}) Weekend Off-peak (ULO_{OFF}), Mid-peak (ULO_{MID}), and On-peak (ULO_{ON}). 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 four prices are calculated to recover the RPA, given the load shape of ULO customers. The RPP Manual specifies that the mid-peak and weekend off-peak prices are equal to the standard TOU mid-peak and off-peak prices, respectively. Furthermore, the RPP Manual specifies that the on-peak price period be approximately 10 times greater than the ultra-low overnight price.

The ratios developed for the November 1, 2023 price setting are set to align with expected ULO consumption profiles, maintain a strong incentive for electricity consumers to shift their consumption away from On-peak periods, and maintain the same weighted average price consistent with the RPA.

The resulting ULO prices are:

- ULO_{NIGHT} = 2.8 cents per kWh;
- ULO_{OFF} = 8.7 cents per kWh;
- ULO_{MID} = 12.2 cents per kWh; and
- ULO_{ON} = 28.6 cents per kWh.

As defined in the RPP Manual, the time periods for TOU price application are as follows:

The ULO pricing periods are:

- *Overnight* period (priced at ULO_{NIGHT}):
  - *Every day*: 11 p.m. to 7 a.m.
- *Off-peak* period (priced at ULO_{OFF}):
  - *Weekends and holidays*: 7 a.m. to 11 p.m.
- *Mid-peak* period (priced at ULO_{MID})
  - *Weekdays*: 7 a.m. to 4 p.m. and 9 p.m. to 11 p.m.
- *On-peak* period (priced at ULO_{ON})
  - *Weekdays*: 4 p.m. to 9 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 for ULO consumers represents the OEB's best estimate of energy consumption. For this price setting period, there is insufficient data to warrant a change in the load profile from that used with the introduction of ULO.[17] With increased uptake of the ULO program and data that spans a longer period of time, this load profile will be reviewed and updated as necessary.

3.3 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 who 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.

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 consumption from the higher to the lower tier), the OEB forecasts the ratio to be 63% $RPCM_{T1}$ and 37% $RPCM_{T2}$ over the RPP period, this is updated from 61% and 39%, respectively.

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 targeting a 0.85 ratio between Tier 1 and Tier 2 prices.

The resulting tiered prices are:

- $RPCM_{T1}$ = 10.3 cents per kWh; and
- $RPCM_{T2}$ = 12.5 cents per kWh

[17] Ultra-Low Overnight Prices May 1, 2023 to October 31, 2023 – Addendum to the Regulated Price Plan Price Report November 1, 2022 to October 31, 2023, April 2023, available at: https://www.oeb.ca/sites/default/files/rpp-price-report-ULO-20230411.pdf

3.4 Regulated Price Plan Prices Effective November 1, 2023

Table 4 below summarizes the RPP TOU and tiered prices effective November 1, 2023.

Table 4: November 1, 2023 RPP Prices[18]

Standard TOU Prices	Off-peak	Mid-peak	On-peak	Average Price
Price per kWh	8.7¢	12.2¢	18.2¢	11.1¢
% of TOU Consumption	63%	18%	19%	

ULO Prices	Overnight	Weekend	Mid-peak	On-peak	Average Price
Price per kWh	2.8¢	8.7¢	12.2¢	28.6¢	11.1¢
% of ULO Consumption	33%	20%	31%	16%	

Tiered Prices	Tier 1	Tier 2	Average Price
Price per kWh	10.3¢	12.5¢	11.1¢
% of Tiered Consumption	63%	37%	

[18] Values in Table 4 may not result in the exact Average Price due to rounding

4. Variance Account

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 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, 2023, the cumulative discrepancy was a deficit of approximately $100 million, but it is expected to increase to $342 million by October 31, 2023, due to differences between current rates and forecast supply costs in September and October 2023. 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 a single RPA in this report, the residential tier thresholds are 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.
- 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 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 in the variance account by 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 (Deficit)