Ontario

Regulated Price Plan Supply Cost Report

May 1, 2019 to April 30, 2020

Ontario Energy Board

April 17, 2019

Executive Summary

Under the *Ontario Fair Hydro Plan Act, 2017* (OFHP Act), the basis on which Regulated Price Plan (RPP) prices are set by the Ontario Energy Board (OEB) is different from the basis on which the OEB set RPP prices under section 79.16 of the *Ontario Energy Board Act, 1998* (OEB Act).[1] Under the OFHP Act, RPP prices are not set on a forecast of the cost of supply over time, but rather are set based on the methodology set out in Ontario Regulation 195/17 (Fair Adjustment under Part II of the Act) (OFHP Regulation) made under the OFHP Act. RPP prices and the GA Modifier for the period May 1, 2019 to October 31, 2019 as determined by the OEB under the OFHP Act are set out in the OEB's April 17, 2019 report *Regulated Price Plan Prices and the Global Adjustment Modifier for the Period May 1, 2019 to October 31, 2019*.

While a forecast of the cost of supply is therefore not required for the purposes of setting RPP prices for the forecast period, such a forecast is required to determine the "GA Modifier". For consumers that are eligible for electricity bill relief under the OFHP Act but are not paying RPP prices, the GA Modifier provides electricity bill mitigation by reducing the Global Adjustment charges that these consumers would otherwise pay. The estimated RPP supply cost for the May 1, 2018 to April 30, 2019 price-setting period was set out in the OEB's April 19, 2018 *Regulated Price Plan Supply Cost Report: May 1, 2018 to April 30, 2019.*

The estimated RPP supply cost provided in this Report was developed based on the methodology set out in the OEB's *Regulated Price Plan Manual.*[2]

The calculation of the total RPP electricity supply cost for the forecast period is informed by several separate forecasts.

Average RPP Supply Cost

The forecast of the simple average market price for the forecast period is $18.73/MWh (or 1.873 cents per kWh). After accounting for the consumption pattern of RPP consumers, the average market price for electricity used by RPP consumers increases to $20.68/MWh (or 2.068 cents per kWh).

The combined effect of all other inputs affecting the RPP supply cost increase this per kilowatt-hour price and are captured by the Global Adjustment. The forecast net impact of the Global Adjustment is to increase the average RPP supply cost for RPP customers by $102.22/MWh (or 10.222 cents per kWh).

The forecast supply cost also considers the uncertainty associated with actual market prices and actual market demand as both are subject to random effects. Consequently, a minor adjustment is made to the RPP supply cost to account for the fact that these random effects are more likely to

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[1] On March 21, 2019, the government introduced Bill 87, the *Fixing the Hydro Mess Act, 2019.* If passed, the provisions of the OFHP Act under which the OEB has been setting RPP prices since July 1, 2017 will be repealed.

[2] Regulated Price Plan Manual, version issued February 16, 2016.

increase than to decrease supply costs during the forecast period. This adjustment was determined to be $1.00/MWh (or 0.100 cents per kWh).

As set out in Table ES-1, the resulting average RPP supply cost for the forecast period is $123.89/MWh (or 12.389 cents per kWh). This is $2.48/MWh, or 0.248 cents per kWh, lower than the forecast cost of $126.37/MWh determined for the May 1, 2018 to April 30, 2019 period.[3]

Table ES-1: Average RPP Supply Cost Summary

RPP Supply Cost Summary for the period from May 1, 2019 through April 30, 2020			$/MWh
Forecast Wholesale Electricity Price - Simple Average			$18.73
Load-Weighted Costs for RPP Consumers			
	Wholesale Electricity Cost - RPP-Weighted		$20.68
	Global Adjustment	+	$102.22
	Adjustment to Address Bias Towards Unfavourable Variance	+	$1.00
	Adjustment to Clear Existing Variance[4]	+	$0.00
Average Supply Cost for RPP Consumers		**=**	**123.89**

Source: Power Advisory

Regulated Price Plan Prices as Calculated under the OEB Act

The OFHP Regulation requires the OEB to publish the RPP prices that would have been in effect on May 1, 2019 if they had been determined by the OEB under section 79.16 of the OEB Act, without taking into account any forecasted impact of any provision of the OFHP Act.

There are two RPP pricing structures. One is for consumers with eligible time-of-use (or “smart”) meters who pay time-of-use (TOU) prices that are based on three periods: Off-Peak (with a price of $RPEM_{OFF}$), Mid-Peak ($RPEM_{MID}$) and On-Peak ($RPEM_{ON}$). These consumers make up the majority of RPP consumers.

The second RPP pricing structure is a tiered structure for consumers with conventional meters.

RPP consumers that are not on TOU pricing pay prices in two tiers; one price (referred to as $RPCM_{T1}$) for monthly consumption up to a tier threshold and a higher price (referred to as $RPCM_{T2}$) for consumption over the threshold. The threshold for residential consumers changes twice a year on a seasonal basis: to 600 kWh per month during the summer season (May 1 to October 31) and to 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.

[3] See the April 19, 2018 *Regulated Price Plan Supply Cost Report: May 1, 2018 to April 30, 2019*.

[4] As discussed in Section 2.2.8, the OEB has adopted a value of $0.00 for the variance clearance adjustment.

Table ES-2 provides the RPP prices that would have been in effect on May 1, 2019 if they had been determined by the OEB under section 79.16 of the OEB Act.

Table ES-2: May 1, 2019 RPP Prices as Calculated under the OEB Act (Absent any Forecasted Impact of the OFHP Act)

Time-of-Use RPP Prices	Off-Peak	Mid-Peak	On-Peak	Average Price
Price per kWh	9.8¢	14.3¢	19.9¢	12.4¢
% of TOU Consumption	65%	17%	18%	
Tiered RPP Prices	**Tier 1**		**Tier 2**	**Average Price**
Price per kWh	11.6¢		13.3¢	12.4¢
% of Tiered Consumption	55%		45%	

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1. Introduction

Under amendments to the *Ontario Energy Board Act, 1998* (OEB 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 O. Reg. 95/05 (Classes of Consumers and Determination of Rates) made under the OEB Act.

Since July 1, 2017, RPP prices have been set under the *Ontario Fair Hydro Plan Act, 2017* (OFHP Act) using a methodology prescribed by regulation rather than being based on a forecast of the cost of supply over time. RPP prices and the GA Modifier for the period May 1, 2019 to October 31, 2019 as determined by the OEB under the OFHP Act are set out in the OEB's April 17, 2019 report *Regulated Price Plan Prices and the Global Adjustment Modifier for the Period May 1, 2019 to October 31, 2019*.

While a forecast of the cost of supply is therefore not required for the purposes of setting RPP prices, such a forecast is required to determine the "GA Modifier"[5].

For consumers that are eligible for electricity bill relief under the OFHP Act but are not paying RPP prices, the GA Modifier provides electricity bill mitigation by reducing the Global Adjustment charges that these consumers would otherwise pay. As set out in the OFHP Act, these consumers are:

- eligible for the RPP, but have opted out for a retail contract or for market-based pricing; and,
- not eligible for the RPP, but eligible for the 8% rebate under the *Ontario Rebate for Electricity Consumers Act, 2016*.

This Report sets out details of the calculation of the RPP prices that would have been effective on May 1, 2019 if they had been determined under section 79.16 of the OEB Act, based on the methodology set out in the OEB's *Regulated Price Plan Manual* (RPP Manual[6]).

This Report consists of three chapters as follows:

- Chapter 1. Introduction
- Chapter 2. Calculating the RPP Supply Cost
- Chapter 3. Calculating RPP Prices

[5] When the OEB set RPP prices and the GA Modifier for the May 1, 2018 to April 30, 2019 period, the forecast of the supply cost was also required to support invoicing requirements under Ontario Regulation 196/17 (Invoicing Requirements) made under the OFHP Act. That Regulation was revoked effective March 22, 2019. However, Ontario Regulation 195/17 (Fair Adjustment under Part II of the Act) made under the OFHP Act retains the obligation on the OEB to publish the RPP prices that would have been in effect on May 1, 2019 if they had been determined by the OEB under section 79.16 of the OEB Act.

[6] Regulated Price Plan Manual, version issued February 16, 2016.

1.1 Associated Documents

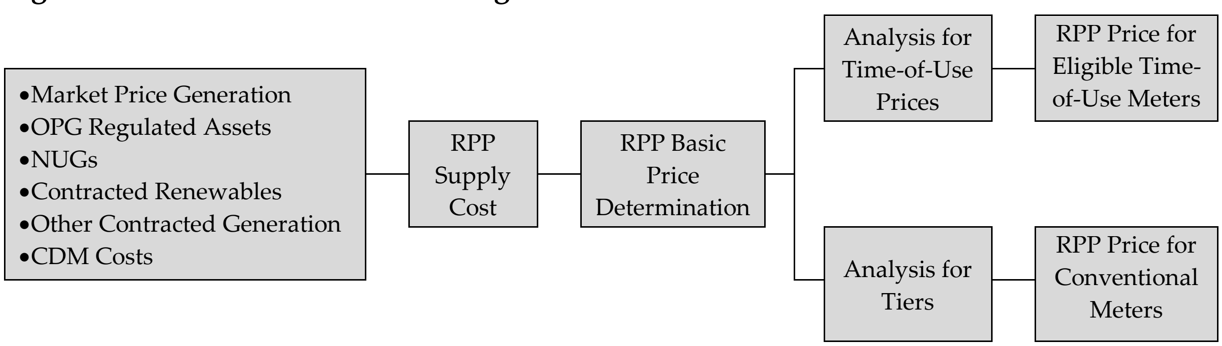
Three documents are closely associated with this Report:

- The RPP Manual, which describes the methodology for setting RPP prices under section 79.16 of the OEB Act;
- The *Ontario Wholesale Electricity Market Price Forecast For the Period May 1, 2019 through October 31, 2020* (Market Price Forecast Report), prepared by Power Advisory LLC, which contains the Ontario wholesale electricity market price forecast and explains the material assumptions used to inform the hourly price forecast.
- The *Regulated Price Plan Prices and the Global Adjustment Modifier for the Period May 1, 2019 to October 31, 2019* report that sets out the RPP time-of use (TOU) and tiered prices and the GA Modifier for the period May 1, 2019 to October 31, 2019, determined in accordance with the OFHP Act and Ontario Regulation 195/17 (Fair Adjustment under Part II of the Act) made under the OFHP Act.

1.2 Process for RPP Price Calculations

The diagram below illustrates the processes followed to calculate RPP prices for both consumers with conventional meters and those with eligible time-of-use meters. This Report is organized according to this basic process.

Figure 1: Process Flow for Calculating the RPP Price



Source: RPP Manual

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 May 1, 2019 to April 30, 2020 period (forecast period) requires forecast data for the variables in Equation 1. Most of the variables depend on more than one underlying data source or assumption. This chapter describes the data or assumption source for each of the variables 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;[7]
- A is the amount paid to prescribed generators in respect of the output of their prescribed generation facilities;[8]
- 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 Independent Electricity System Operator (IESO) with respect to its payments under certain contracts with renewable generators;

[7] 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.* "G" in the expression in square brackets integrates two separate components of the Global Adjustment formula (G and H). "E" and "F" in the expression in square brackets include certain generation contracts that are associated with "G" in O. Reg. 429/04. This is necessary to ensure that there is no double-counting and thus over-recovery of generation costs because all RPP supply is included in "M". As discussed below, 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 prior to taking into account the effect of the OFHP Act.

[8] As set out in regulation O. Reg. 53/05 (Payments under Section 78.1 of the Act) made under the OEB Act, the OEB sets payment amounts for energy produced from Ontario Power Generation's nuclear and certain hydro-electric generating stations (the prescribed assets). The OEB's most recent Order setting base payment amounts (EB-2018-0243) was issued on February 21, 2019.

- 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 (a) the amount paid by the IESO for its other procurement contracts for generation or for demand response or Conservation and Demand Management (CDM), and (b) the sum of any OEB-approved amounts for OEB-approved CDM programs that are payable by the IESO to distributors; and
- H is the amount associated with the variance account held by the IESO. This includes any existing variance account balance needed to be recovered (or disbursed) in addition to any interest incurred (or earned).

The forecast per unit RPP supply cost will be the total RPP supply cost (C_{RPP}) divided by the total forecast RPP demand. RPP prices will be 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 calculation of the total RPP supply cost requires a forecast of the stochastic adjustment, which is not included in Equation 1. The stochastic adjustment is included in the RPP Manual as an additional cost factor calculated outside of Equation 1.

On June 21, 2018, the federal *Greenhouse Gas Pollution Pricing Act* (Greenhouse Gas Act) received Royal Assent. The Greenhouse Gas Act applies in provinces and territories where there is no provincial or territorial carbon pricing policy that meets the federal standard. In 2018, the government of Ontario terminated Ontario's cap-and-trade program and repealed the *Climate Change Mitigation and Low-carbon Economy Act, 2016*.

Effective January 1, 2019, gas-fired generation in Ontario (among others) is subject to Part II of the Greenhouse Gas Act, which introduces an output-based pricing system (OBPS). Accordingly, this RPP forecast accounts for the impact of the OBPS over the forecast period. Participants in the OBPS are required to report and manage their own carbon-related compliance obligations, and have the following options to satisfy annual emissions that exceed their sector-based emission intensity benchmark: (i) pay the excess emissions charge; (ii) submit surplus credits issued by the federal government; or (iii) submit eligible offset credits. The Market Price Forecast Report assumes that gas-fired generators will satisfy their OBPS obligations by paying the excess emissions charge.

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 Greenhouse Gas Act ($20.00/tonne of CO_2e in 2019 and $30.00/tonne of CO_2e in 2020)[9].

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 below shows forecast seasonal on-peak, off-peak, and average prices. The prices provided in Table 1 are simple averages over all of the hours in the specified period (i.e., they are not load-weighted). These on-peak and off-peak periods differ from and should not be confused with the TOU periods associated with the RPP TOU prices discussed later in this report.

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

Quarter	Calendar Period	On-Peak	Off-Peak	Average
Q1	May 2019 - Jul 2019	$20.83	$9.78	$14.85
Q2	Aug 2019 - Oct 2019	$22.13	$12.09	$16.69
Q3	Nov 2019 - Jan 2020	$26.75	$12.92	$19.23
Q4	Feb 2020 - Apr 2020	$28.38	$20.94	$24.26
Average	**May 2019 - Apr 2020**	**$24.50**	**$13.89**	**$18.73**

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.

The forecasts of the monthly ratios of load-weighted vs. simple average HOEP are based on actual prices between April 2005 and March 2019. The on-peak to off-peak ratio is also based on data through March 2019.

[9] https://laws-lois.justice.gc.ca/eng/acts/G-11.55/page-43.html - h-76/

As shown in Table 1, the forecast simple average HOEP for the period May 1, 2019 to April 30, 2020 is $18.73/MWh (1.873 cents per kWh). The forecast of the load weighted average price for RPP consumers ("M" in Equation 1) is $20.68/MWh (2.068 cents per kWh), or $1.23 billion in total, the result of RPP consumers having load patterns that are more peak oriented than the overall system.

2.2.2 RPP Share of the Global Adjustment

Alpha ("α") in Equation 1 represents the 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 increased from 16.7% for the July 2017 to June 2018 period, to 19.3% for the July 2018 to June 2019 period. This increase was due to two factors: (a) increased participation in the Ontario Government's Industrial Conservation Initiative resulting from the lowering of the threshold for Class A eligibility in April 2017, and (b) an increase in the average load factor (the ratio of coincident peak demand to annual energy consumption) across all Class A customers. The increase in load factor is likely due to the fact that one of the Top 5 Peaks in the May 2017 to April 2018 Base Period occurred in the winter. The Class A share of Global Adjustment charges is forecast to decrease to 18.5% for the July 2019 to June 2020 period, again due to two expected changes: (a) a small additional increase in the number of customers opting in to Class A, and (b) a decrease in the average Class A load factor, due to the fact that all five of the Top 5 Peaks in the May 2018 to April 2019 Base Period occurred during the summer. On average, Class B's share of the Global Adjustment is forecast to be 80.4% over the forecast period.

The government is currently consulting on the design and effectiveness of current industrial electricity pricing and programs[11]. Changes resulting from these consultations could impact RPP supply costs in the future, and they will be reflected as appropriate in future RPP supply cost forecasts when such changes, if any, are known.

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 59 TWh, or 61% of total Class B consumption. The RPP share varies with the seasons, ranging between 55% and 66%. RPP consumers' share of monthly Global Adjustment charges therefore ranges between 38% and 47%. Over the entire forecast period, the RPP consumers' share of the Global Adjustment is forecast to be 49.6%. The value of $\boldsymbol{\alpha}$ therefore 0.496.

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[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).

[11] https://www.ontario.ca/page/consultation-industrial-electricity-prices

2.2.3 Cost Adjustment Term for Prescribed Generators

This section covers the second term of Equation 1:

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

The prescribed generators are comprised of the rate-regulated nuclear and hydroelectric facilities of OPG for which the OEB sets payment amounts. The payment amounts for OPG's prescribed generation are \$89.70/MWh in 2019 and \$94.96/MWh in 2020 for nuclear generation, and \$45.46/MWh in 2019 and \$45.48/MWh[12] in 2020 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-2018-0243 and EB-2016-0152.

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 hydraulic generation, and multiplying those market values by the volume of nuclear and prescribed hydraulic generation. The value of A is \$5.51 billion, and the value of B is \$1.47 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 non-utility generators (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 \$0.17 billion, and the value of "D" (i.e., the market value of the NUG output) is estimated to be \$0.03 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:

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[12] The 2020 hydroelectric payment amount is comprised of riders approved in EB-2016-0152 and EB-2018-0243, and an estimated base payment amount. The 2020 hydroelectric base payment amount was estimated by escalating the approved 2019 base payment amount by 1.1%, the escalation approved for 2019 hydroelectric payment amounts in EB-2018-0243.

- o Renewable Energy Supply (RES) Request for Proposals (RFP) Phases I, II and III;
- o the Renewable Energy Standard Offer Program (RESOP);
- o the Feed-In Tariff (FIT) Program;
- o the Hydroelectric Standard Offer Program (HESOP);
- o the Hydroelectric Energy Supply Agreements (HESA) directive, covering new and redeveloped hydro facilities;
- o the Hydro Contract Initiative (HCI), covering existing hydro plants;
- o the Energy from Waste program; and
- o Non-Utility Generators 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 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 market revenue (based on market prices in the Market Price Forecast Report) at the time that output is generated.

The value of "E" in Equation 1 (i.e., the contract cost of renewable generation) is estimated to be $4.54 billion, and the value of "F" (i.e., the market value of renewable generation) is estimated to be $0.41 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;

[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

2. demand side management, demand response, capacity and energy sales 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 generation contracts as well as one demand response contract;
- The "early mover", "Accelerated CES" and "Northern York Region" contracts; and
- Contracts awarded for 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) 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 supply cost 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 to be $7,900 per megawatt-month,[14]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 conservation and demand management (CDM) initiatives delivered under contract with the IESO is also captured in term G of Equation 1. On March 21, 2019, the Conservation First Framework was discontinued by Ministerial directive, and replaced with a new Interim Framework effective April 1, 2019.[15] Under the Interim Framework, which runs from April 1, 2019 to December 31, 2020, the IESO will centrally deliver a reduced portfolio of CDM programs. All local programs will be discontinued, although there will be an opportunity for electricity distributors to apply to the IESO for limited funding for cost-effective local programs. The forecast of CDM initiative costs for the forecast period reflects an estimate of the cost reduction implications of these changes.

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[16]. 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.

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

[15] For information on the IESO's CDM activities, see the IESO's dedicated web page at: http://www.ieso.ca/Sector-Participants/Conservation-Delivery-and-Tools/Interim-Framework

[16] In 2005, Bruce Power entered into an initial Bruce Power Refurbishment Implementation Agreement in relation to the operation of Bruce Units 1 and 2. In December 2015, the IESO and Bruce Power entered into an Amended and Restated Bruce Power Refurbishment Implementation Agreement.

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

The value of "G" in Equation 1 (i.e., net cost of Bruce nuclear, gas and Lennox generation plus CDM programs) is estimated to be $3.94 billion.

2.2.7 Estimate of the Global Adjustment

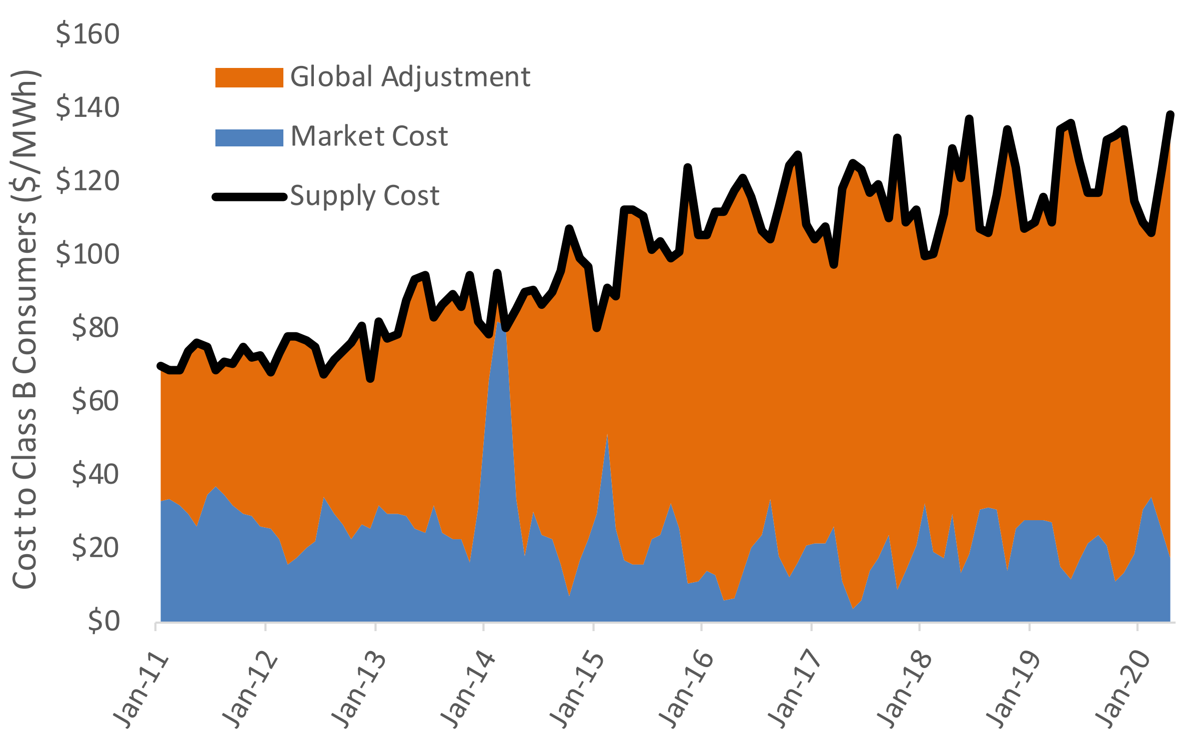
The total Global Adjustment is estimated to be $12.3 billion. The RPP share of this (i.e., α times the total cost) is estimated to be $6.1 billion, or $102.22/MWh (10.222 cents per kWh). This is the forecast of the average Global Adjustment cost per unit for RPP consumers over the period from May 1, 2019 to April 30, 2020.

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

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

This is illustrated in Figure 2, which shows how the Global Adjustment is expected to change over the next 12 months.

Figure 2: Components of the RPP Supply Cost



Source: Power Advisory

Overall, RPP supply costs have decreased by 2.0% between this forecast period and the supply costs which were forecast for the May 2018 to April 2019 period, as set out in the OEB's April 19, 2018 *Regulated Price Plan Supply Cost Report: May 1, 2018 to April 30, 2019.* A number of factors have contributed to this change:

- Market prices are expected to be lower than in the previous forecast, primarily due to lower effective carbon prices. The impact of the federal excess emissions charges is significantly lower than the impact of the cap-and-trade system of carbon pricing which was in effect at the time of the previous forecast.
- The forecast of CDM initiative costs for the forecast period reflects an estimate of the cost reduction resulting from the Interim Framework.
- Contracts for some Non-Utility Generators are scheduled to terminate.
- Offsetting the above factors, payment amounts for Ontario Power Generation's (OPG) prescribed generation facilities will be higher than in the previous RPP forecast period. Payment amounts for OPG's prescribed generation were $82.57/MWh for nuclear generation and $42.70/MWh for hydroelectric generation. They are currently (in 2019) $89.70/MWh and $45.46/MWh respectively, and they are scheduled to increase to $94.96/MWh and $45.48/MWh[17] respectively in 2020. These payment amounts, which reflect both base payment amounts and rate riders, were set out in the following two OEB decisions: EB-2018-0243 and EB-2016-0152.
- Some new generation will be coming into service, which will put upward pressure on the Global Adjustment. Details on capacity additions during the forecast period are provided in the Market Price Forecast Report. Some of the new capacity listed was also assumed to come into service in the previous RPP forecast; for example, in the previous forecast, the Napanee Generating Station was expected to come into service in the third quarter of 2018, based on the March 21, 2018 *18-Month Outlook*; it is now expected to come into service in the second quarter of 2019. This means that only part of the cost of this facility is incremental compared to the previous RPP supply cost forecast.
- Class B consumers' share of Global Adjustment charges is expected to decrease slightly, as discussed above, even while some customers shift from Class B to Class A.

2.2.8 Cost Adjustment Term for IESO Variance Account

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

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

Previously, the calculation of RPP supply cost included variable H which represented the variance between RPP revenue and actual costs of RPP supply as reported by the IESO. The IESO has not tracked this variance since RPP prices started to be set under the OFHP Act. Consequently, the OEB has adopted a value of $0.00 for variable H.

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[17] The 2020 hydroelectric payment amount is comprised of riders approved in EB-2016-0152 and EB-2018-0243, and an estimated base payment amount. The 2020 hydroelectric base payment amount was estimated by escalating the approved 2019 base payment amount by 1.1%, the escalation approved for 2019 hydroelectric payment amounts in EB-2018-0243.

2.3 Correcting for the Bias Towards Unfavourable Variances

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.

Based on OEB experience, the Adjustment to Address Bias Towards Unfavourable Variance is set at $1.00/MWh (0.100 cents per kWh). This amount is included in the 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 for each generation type, including Global Adjustment payments and market price payments, where applicable.

Table 2: Total Electricity Supply Cost

	% of Total Supply	% of Total GA	Total Unit Cost (cents/kWh)
Nuclear	55%	43%	8.0¢
Hydro	25%	13%	6.3¢
Gas	9%	12%	13.2¢
Wind	8%	14%	14.8¢
Solar	2%	13%	48.1¢
Bioenergy	1%	2%	23.0¢

Source: Power Advisory

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

The total RPP supply cost is estimated to be $7.4 billion.

The following table itemizes the various steps discussed above to arrive at an average RPP supply cost of $123.89/MWh. This average supply cost corresponds to an average RPP price, which is referred to as RPA, of 12.389 cents per kWh.

Table 3: Average RPP Supply Cost Summary

RPP Supply Cost Summary for the period from May 1, 2019 through April 30, 2020		$/MWh
Forecast Wholesale Electricity Price - Simple Average		$18.73
Load-Weighted Costs for RPP Consumers		
Wholesale Electricity Cost - RPP-Weighted		$20.68
Global Adjustment	+	$102.22
Adjustment to Address Bias Towards Unfavourable Variance	+	$1.00
Adjustment to Clear Existing Variance[18]	+	$0.00
Average Supply Cost for RPP Consumers	=	**$123.89**

Source: Power Advisory

[18] As discussed in Section 2.2.8, the OEB has adopted a value of $0.00 for the variance clearance adjustment.

3. Calculating the RPP Price

The previous chapter calculated a forecast of the total RPP supply cost. Given the forecast of total RPP demand, it also produced a computation of the average RPP supply cost and the average RPP supply price, known as the RPA. This chapter sets out the remaining steps in calculating the RPP TOU and tiered prices that would have been effective on May 1, 2019 if they had been determined under section 79.16 of the OEB Act without taking into account any forecasted impact of any provisions of the OFHP Act. As discussed in chapter 1, this calculation is being done for purposes other than setting the RPP prices that will be payable by RPP consumers in the May 1, 2019 to October 31, 2019 period. Those prices are set out in the OEB's April 17, 2019 report *Regulated Price Plan Prices and the Global Adjustment Modifier for the Period May 1, 2019 to October 31, 2019.*

3.1 TOU Prices as Calculated under the OEB Act

For those consumers with eligible time-of-use (or "smart") meters, 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 is 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 supply cost, given the load shape of TOU customers. The RPP Manual does not prescribe the order in which prices are calculated.

The first step in calculating the TOU prices for this forecast period was to set the Off-peak price, or $RPEM_{OFF}$. This price reflects the forecast market price during that period, including the Global Adjustment. The Mid-peak price, $RPEM_{MID}$, was similarly calculated. After these two prices were calculated, and given the forecast levels of consumption during each of the three periods, the calculation of the On-Peak price, $RPEM_{ON}$, is governed by the requirement for the load-weighted average of TOU prices to equal the RPA.

The various components of Global Adjustment costs are allocated to TOU consumption periods based on the type of cost. The costs associated with OPG's 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 GA is allocated to both Mid-peak and On-Peak consumption because these generators serve non-Off-Peak consumption. As well, approximately one-quarter of the stochastic adjustment was allocated to the Mid-Peak price and three-quarters was allocated to the On-Peak price because the majority of risks covered by the adjustment are borne during these time periods.

The overall effect of this allocation is to set the differential between the On-Peak and Off-Peak prices to 2.0:1. This ratio strengthens the incentive for electricity consumers to shift their consumption away from On-Peak periods, when their electricity prices are highest.

The OEB has calculated the RPP TOU prices that would have been effective on May 1, 2019 if determined under section 79.16 of the OEB Act as follows:

- $RPEM_{OFF}$ = 9.8 cents per kWh
- $RPEM_{MID}$ = 14.3 cents per kWh, and
- $RPEM_{ON}$ = 19.9 cents per kWh.

These prices reflect the seasonal change in the TOU pricing periods which will take effect on May 1, 2019 and November 1, 2019. 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*: 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 is different from the load profile for non-TOU RPP consumers. 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.

3.2 Tiered Prices as Calculated under the OEB Act

The final step is to calculate tiered prices. There is a two-tiered pricing structure: $RPCM_{T1}$ (the price for consumption at or below the tier threshold) and $RPCM_{T2}$ (the price for consumption above the tier threshold). The tier threshold is an amount of consumption per month.

The tiered prices are calculated so that the average per unit revenue would be equal to the RPA. This is achieved by maintaining the ratio between the original upper and lower tier prices (i.e., the ratio between 4.7 and 5.5 cents per kWh) and forecasting consumption above and below the threshold in each month of the forecast 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 15-17% difference between Tier 1 and Tier 2 prices.

The OEB has calculated the RPP tiered prices that would have been effective on May 1, 2019 if determined under section 79.16 of the OEB Act as follows:

- $RPCM_{T1}$ = 11.6 cents per kWh; and,
- $RPCM_{T2}$ = 13.3 cents per kWh.

Table 4 below summarizes what RPP TOU and tiered prices would have been on May 1, 2019 if determined under section 79.16 of the OEB Act without taking into account any forecasted impact of any provision of the OFHP Act.

Table 4: May 1, 2019 RPP Prices as Calculated under the OEB Act (Absent Any Forecasted Impact of the OFHP Act)

Time-of-Use RPP Prices	Off-Peak	Mid-Peak	On-Peak	Average Price
Price per kWh	9.8¢	14.3¢	19.9¢	12.4¢
% of TOU Consumption	65%	17%	18%	
Tiered RPP Prices	**Tier 1**		**Tier 2**	**Average Price**
Price per kWh	11.6¢		13.3¢	12.4¢
% of Tiered Consumption	55%		45%	