Ontario

DRAFT

Regulated Price Plan

Manual

Ontario Energy Board

February 10, 2005

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1. INTRODUCTION

About this Manual

Under amendments to the *Ontario Energy Board Act, 1998* (the "Act") contained in the *Electricity Restructuring Act, 2004*, the Ontario Energy Board (the "Board") has been mandated to develop an annual regulated price plan (the "RPP"). The RPP is intended to replace the electricity commodity pricing regime that went into effect on April 1, 2004, and is expected to take effect on April 1, 2005 for all eligible consumers unless the Government prescribes a later date.

This Regulated Price Plan (RPP) Manual (the "Manual") has been prepared by the Board within the context of a larger regulatory proceeding (designated as RP-2004-0205) in which interested parties have assisted the Board in developing the elements of the RPP.

This Manual describes the processes and methodologies the Board will use to support its responsibilities with respect to setting prices under the RPP. Implementation of the RPP by licensed distributors and licensed retailers is addressed primarily in the Board's revised Standard Supply Service Code.

Related documents and Board decisions that describe processes and actions that other parties will use to fulfill their responsibilities under the RPP include:

Ontario Energy Board Instruments

- Retail Settlement Code (RSC);
- Standard Supply Service Code (SSS Code);
- Rate Orders; and
- Licences.

Independent Electricity System Operator (IESO) Instruments

- Ontario Market Rules.

This Manual consists of 6 chapters as follows:

- Chapter 1. Introduction
- Chapter 2. Methodology for Calculating the RPP Supply Cost
- Chapter 3. Methodology and Timing for Setting RPP Prices
- Chapter 4. Methodology and Timing for Variance Tracking
- Chapter 5. Timing for RPP Price Adjustments or Price Structure Changes
- Chapter 6. Methodology for Determining Final Variance Settlement Amounts

Purpose

The purpose of this Manual is to define and explain the methodologies and processes that the Board will use in fixing or approving electricity commodity prices that will be charged to RPP consumers.

This Manual includes processes for calculating and setting the RPP prices, including separate prices for consumers with conventional meters and for consumers with eligible time-of-use (or "smart") meters; for monitoring and truing up variances between the forecast RPP price and the actual cost of RPP supply; for resetting the RPP price; and for calculating the final variance settlement amount for consumers leaving the RPP.

In keeping with Government policy statements and legislation, the RPP prices to be set by the Board will reflect the price of supply over time.

Authority for the OEB to Establish the RPP

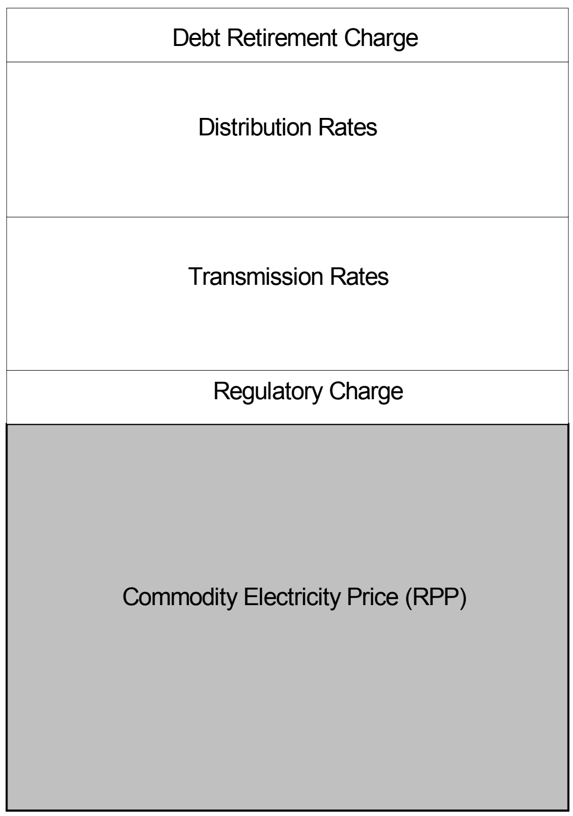
Subsections 78 (3.1) and 78 (3.2) of the Act assign the Board responsibility for approving or fixing prices for eligible consumers. Consumer eligibility for RPP prices is determined by Government regulation. The Act (subsection 78 (3.3)) requires the Board to forecast the cost of electricity used by these consumers and to ensure that the prices reflect that cost. The Act further requires the Board to adjust RPP prices with a view to clearing any balances in the Ontario Power Authority (OPA) variance account over a 12-month period.

This Manual confirms that the initial RPP commodity prices fixed by the Board for both conventional and eligible time-of-use meters will remain in effect for a period of at least 12 months, as required by law.

Total Prices Paid by Consumers

The commodity electricity prices under the RPP comprise only one element of the total price paid by consumers taking RPP supply. Figure 1 shows the other elements that comprise the final retail consumer bill. The height of the bars in the diagram is roughly proportional to each element's relative share of the total retail electricity bill. There is also a brief description of each component of the consumer bill following the diagram.

Figure 1: Retail Electricity Price under the Regulated Price Plan



Commodity electricity price: This charge is for the electricity consumers use, which they buy either from their distributor at the RPP price or through a licensed electricity retailer at a contract price.

Distribution charge: This component covers the costs distributors incur in delivering electricity to the consumer's homes or businesses. It includes fixed costs; that is, they do not change with the amount of electricity used. It also includes the costs of building and maintaining infrastructure, such as wires and hydro poles, which varies with the amount of electricity used.

Transmission charge: This component covers the costs of delivering electricity from the generating stations to the distributor along the high-voltage transmission system (also called the transmission grid) owned by Hydro One Networks Inc. Transmission costs vary with the amount of electricity used.

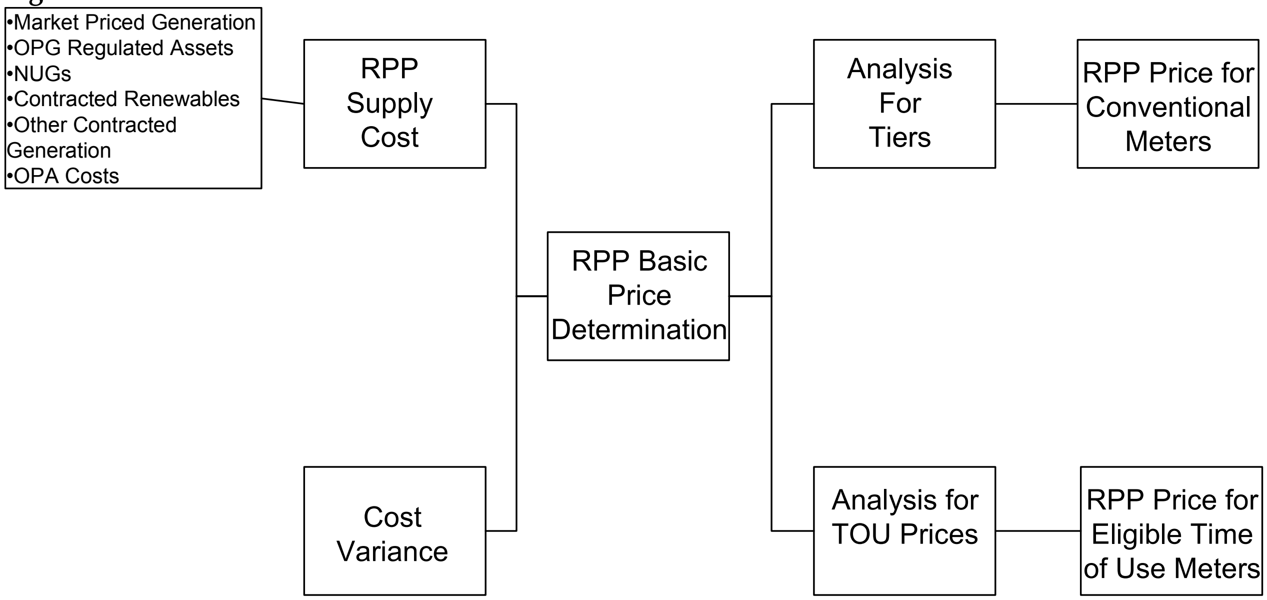
Regulatory charge: This includes the IESO's costs to operate Ontario's electricity market and other administrative charges.

Debt-retirement charge: This charge of 0.7 cents per kWh has been set by the Ontario Ministry of Finance to pay down the residual stranded debt of the former Ontario Hydro.

Process for RPP Price Determinations

Figure 2 below illustrates the process for setting RPP prices and the decisions to be made in that process. The RPP supply cost and the accumulated cost variance (carried by the OPA) both contribute to the base RPP price, which is set to recover the full costs of supply. The remainder of the process is also based on forecasts of prices and of consumption patterns. For consumers with conventional meters, the next step is to analyze the tier structure of their prices. From the tier structure is derived the RPP prices that such consumers will pay. For consumers with eligible time-of-use meters, the next step is to analyze the pattern of prices in order to determine what the pattern of prices should be, both in terms of the three price levels (on-peak, mid-peak and off-peak) and in terms of the daily times of application of these prices. These may differ seasonally.

Figure 2: Process for RPP Price



This Manual is organized according to this basic process. Chapter 2 describes the computation of the RPP supply cost. Chapter 3 explains the methodology used for setting RPP prices. Chapter 4 describes tracking and monitoring the Ontario Power Authority's variance account. Chapter 5 deals with the timing of price adjustments and price structure changes. Chapter 6 describes the methodology used for determining the final variance settlement amounts for consumers that leave the RPP.

Using this Manual

The processes and methodologies in this Manual relate to activities of the Board and, for one particular function, to distributors or retailers with settlement responsibilities for RPP consumers. The Board will use these methodologies and processes to assist in determining retail electricity commodity prices for the RPP and to support the calculation of final variance settlement amounts for consumers leaving the RPP. This Manual also serves as a guide to interested parties in understanding how the Board will determine prices for the Regulated Price Plan.

Roles of Participants

This Manual describes the roles of various participants in the RPP process, but does not directly place obligations on them. However, other instruments (such as the revised SSS Code) refer to the Manual with respect to some obligations, particularly the determination of the final variance settlement amount for consumers leaving RPP supply. Requirements placed directly on participants are contained in legislation, regulations, licenses, codes and the market rules, as applicable. The majority of RPP requirements and obligations for electricity distributors are set out in the SSS Code, while retailer obligations are contained in the RSC.

Roles of distributors

Distributors are the point of contact, both physical and financial, for most retail consumers in the electricity system. Some of their current roles could be played by other entities; their irreducible role is that of providing distribution service allowing electricity to be delivered to the place of consumption. Under section 29 of the Electricity Act, a distributor is also required to sell electricity to every person connected to the distributor's system, except those consumers that opt to purchase electricity from a competitive retailer. Other roles include:

- Meter reading;
- Billing;
- Electricity supplier for consumers taking RPP supply; and
- Electricity supplier for consumers not eligible for RPP supply and not taking supply from a competitive retailer.

Roles of retailers

Competitive retailers offer to sell electricity to consumers who either are not eligible for RPP supply or who choose not to take supply under the RPP. They may bill consumers for their supply, or they may choose to have the distributor bill on their behalf. A relatively small number of consumers of retailers may have the benefit of RPP pricing unless and until the consumer enters into a new retail contract or renews the existing one. This is limited to those consumers that entered into a retail contract on or before November 11, 2002 but that are nonetheless eligible for the RPP in accordance with Government regulations.

Roles of the Independent Electricity System Operator (IESO)

The IESO's main role is to administer the wholesale electricity market in Ontario, scheduling and dispatching the electricity system to maintain safe and reliable electricity supply. It also settles the wholesale market with all wholesale market participants, both buyers and sellers. The IESO roles with respect to the RPP are:

- to adjust its monthly settlements to reflect the global adjustment[1];
- to estimate the global adjustment daily; and
- to provide the Board with information necessary for the determination of RPP prices.

Roles of the Ontario Power Authority (OPA)

The OPA is responsible for planning the electricity supply system in Ontario, including forecasting electricity demand and supply adequacy and contracting for additional sources of supply or demand management, if necessary. With respect to the RPP, the OPA's roles are:

- to hold in a variance account the amounts due to differences between actual commodity electricity supply prices and the forecast-based RPP prices; and
- to provide the Board with information necessary for the determination of RPP prices.

Roles of Ontario Electricity Financial Corporation (OEFC)

OEFC is responsible for holding and defeasing that part of the former Ontario Hydro's debt that was not assigned to the successor operating companies. In conjunction with that responsibility, OEFC became the counterparty to the non-utility generator (NUG) contracts signed by the former Ontario Hydro. As such, it is the metered market participant for the NUGs. OEFC's role with respect to the RPP is to provide the Board with information necessary for the determination of RPP prices.

Definitions

The following defined terms are used in this Manual.

> "Act" means the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, Schedule B;
>
> "Board" means the Ontario Energy Board;

[1] The global adjustment is also referred to as the "Provincial Benefit".

“conventional meter” means a meter other than an interval meter or an eligible time-of-use meter;

“Electricity Act” means the *Electricity Act, 1998*, S.O. 1998, c. 15, Schedule A;

“eligible time-of-use meter” means a meter that measures and records electricity use during each of the periods of the day referred to in section 3.4.1 of the SSS Code cumulatively over a meter reading period;

“final variance settlement amount” means the amount charged or credited to an RPP consumer in accordance with section 3.7 of the SSS Code;

“first term commencement date” means April 1, 2005 or such later date as may be prescribed by regulation as the date on which rates fixed or approved by the Board under section 78(3.1) of the Act take effect;

“global adjustment” or “GA” means the adjustment referred to in section 25.33 of the Electricity Act and made in accordance with regulations made under section;

“IESO” means the Independent Electricity System Operator continued under the Electricity Act;

“interval meter” means a meter that measures and records electricity use on at least an hourly basis;

"Market Rules" means the rules made under section 32 of the Electricity Act;

“non-RPP consumer” means a consumer that is not an RPP consumer;

“Retail Settlement Code” or “RSC” means the code issued by the Board which, among other things, establishes a distributor=s obligations and responsibilities associated with financial settlement among retailers and customers and provides for tracking and facilitating customer transfers among competitive retailers;

“RPP consumer” means a consumer that pays the commodity price for electricity referred to in section 3.3 or 3.4 of the SSS Code;

"second term commencement date" means the date on which a change in the initial value of any of $RPCM_{T1}$, $RPCM_{T2}$, $RPEM_{OFF}$, $RPEM_{MID}$, or $RPEM_{ON}$ referred to in section 3.3 or 3.4 of the SSS Code comes into effect, which date shall not be earlier than the date that is twelve months from the first term commencement date;

"spot market price" means, for a given hour, the Hourly Ontario Energy Price established by the IESO for that hour;[2] and

"Standard Supply Service Code" or "SSS Code" means the code issued by the Board and in effect at the relevant time which, among other things, establishes the manner in which a distributor must meet its obligation to sell electricity under section 29 of the Electricity Act.

Except as defined above, words defined in the Act, the Electricity Act or any regulations made under those Acts have the same meaning when used in this Manual.

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[2] Any adjustment made by the IESO in accordance with regulations made under section 25.33 of the Electricity Act will apply to the spot market price.

2. METHODOLOGY FOR CALCULATING THE RPP SUPPLY COST

Introduction

This chapter describes and explains the methodology for computing the forecast RPP supply cost on which the base RPP price will be based. The methodology is based on forecast information that includes the results of a one-year ahead Ontario market price forecast from a production cost model that produces forecasts of hourly prices and of supply from specific generators.

Topics in this chapter are:

- Overview of the new Ontario electricity market structure;
- Overall methodology for forecasting the RPP supply cost; and
- Computation of the RPP supply cost.

The production cost model currently used for the forecast is maintained and run by a consultant under contract to the Board.

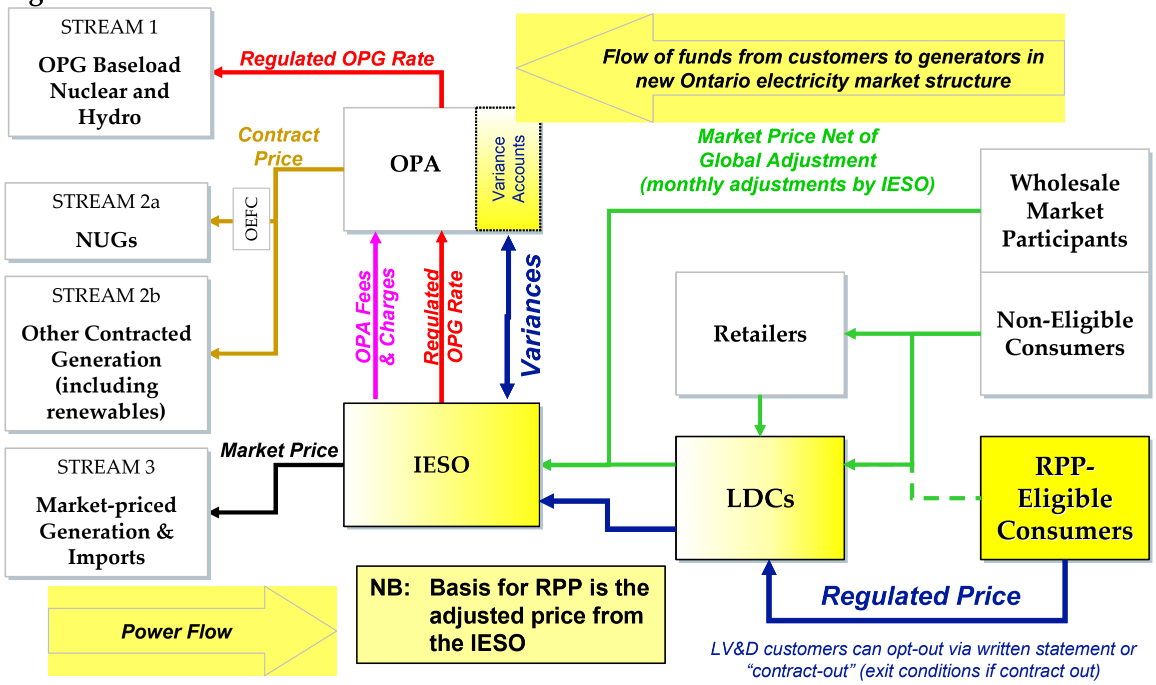
Overview of the New Ontario Electricity Market Structure

The RPP is part of a new structure for the Ontario electricity market created by the *Electricity Restructuring Act, 2004*. Figure 3 below illustrates the new Ontario market structure. In a simplified way, it shows the relationships between the OPA, generators, and the IESO. It also shows how consumers relate to distributors, retailers, and the market.

Figure 3 indicates four streams of generation sources for the RPP. They are priced differently, and their pricing affects the RPP supply cost. This chapter details the methodology for the forecast of each of these cost elements and their integration into the RPP supply cost.

In the new Ontario electricity market, while some generation supply will be paid a market-based price, a large part of that generation supply will not. Rather, such generation supply will have prices determined by contract or regulation, and will largely be settled (paid) through the OPA.[3]

Figure 3: RPP and the New Ontario Market Structure



Overall Methodology for Forecasting the RPP Supply Cost

The supply cost of electricity provided to RPP consumers will be determined in accordance with the rules established by legislation. The cost of electricity to wholesale customers is the amount they would have paid under the Market Rules (that is, the cost of their electricity at the hourly Ontario energy price or HOEP), adjusted at the end of each month by an amount referred to as the global adjustment or "GA".

In the Ontario electricity market, certain contracted or regulated generators receive a final price that is different from the hourly market price paid to them by the IESO. Under changes to the legislation resulting from Bill 100, the IESO keeps track of these differences and adjusts the bills for all market participants to reflect them. The difference is referred to as the "global adjustment".

The RPP supply cost will be the cost of electricity supply for RPP consumers under the Market Rules, adjusted by cost factors relating to each of the other

[3] The OPA is not initially expected to be involved in settling with the non-utility generators or "NUGs" in respect of their supply prices.

streams of supply and by any costs the OPA incurs to carry the RPP-related variance accounts. The costs of these streams are apportioned to RPP consumers in accordance with their share of total provincial electricity demand.

Equation 1 below shows the calculation of the RPP supply cost.

Equation 1

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

- C_{RPP} is the RPP supply cost;
- M is the amount that the RPP supply would have cost under the Market Rules;
- α is the RPP proportion of the total demand in Ontario;[4]
- A is the amount paid to prescribed generators;[5]
- B is the amount those generators would have received under the Market Rules;
- C is the amount paid to NUGs under existing contracts;
- D is the amount those NUGs would have received under the Market Rules for both electricity and ancillary services;
- E is the amount paid to generators contracted to the OPA that are paid according to their ouput (i.e., renewable generators);
- F the amount those generators would have received under the Market Rules;,
- G is the amount paid by the OPA for its other procurement contracts, which will include payments for generators or demand response or demand management; and
- H is the OPA's costs for the variance account.

The forecast per unit cost of the RPP supply will be C_{RPP} divided by the total forecast demand. RPP prices will be based on that forecast per unit cost. For that per unit cost forecast, all the terms in Equation 1 must be forecast. The remainder of this chapter describes the methodology for forecasting these terms, the average per unit cost of RPP, and the methodology for setting the base RPP price.

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

[5] These are generators designated by regulation and whose output is subject (in whole or in part) to a regulated rate set by regulation or by the Board. These are presently expected to be OPG's baseload nuclear and hydro facilities, and are referred to as "stream 1" in **Error! Reference source not found.** above.

In developing this methodology, the Board has taken into consideration the use of the forecast and the relative value of increased precision. Deviations of actual from forecast RPP price will, under the Act and the Electricity Act, be accumulated in a variance account and collected through future charges from consumers taking RPP supply. Since there will inevitably be deviations from the forecast, an increase in precision of the forecast only reduces the size of the variance. Given that some forecast inaccuracy is inevitable due to the large number of variables, the Board has chosen to use reasonable approximations for some calculations, rather than aim for greater precision at higher, unjustifiable costs.

Computation of the RPP Supply Cost

Broadly speaking, the steps involved in forecasting the RPP supply cost are:

1. Forecast wholesale market prices;
2. Forecast load shape for RPP consumers;
3. Forecast the quantities in Equation 1; and
4. Forecast RPP Supply Cost = Total of Equation 1.

The methodology for forecasting the RPP supply cost will describe each term or group of terms in Equation 1 and the methodology for forecasting them.

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 cost of supply under the Market Rules depends on when any particular supply offer is accepted, dispatched and delivered to the grid to meet the last unit of instantaneous Ontario load on the grid. Peak period prices, representing higher marginal cost supply sources, are higher than off-peak period prices. The differences are large enough that ignoring them can introduce errors into the forecast of total RPP supply cost.

The pattern of electricity demand over time is called the load shape. If RPP consumers as a group have a load shape that is close to the average load shape, then a reasonable approximation of their total cost would be to assume that the average market price for this supply is equal to the overall average market price, and the market-based RPP supply cost would then simply be the total energy demand of the RPP consumers times the load-weighted average hourly price.

However, different classes of consumers in Ontario have noticeably different load shapes. Industrial consumers tend to have much flatter load shapes; that is, they tend to use electricity much more evenly over the course of a day and over the seasons. Residential and small commercial consumers, who are the majority of the RPP-eligible consumers, have a load shape with a larger fraction of their demand occurring at peak times (winter mornings and late afternoons and summer mid-afternoons), as they use electricity for lighting, cooking and air-conditioning.

No precise load shape is available for RPP consumers. The approximation widely used is called Net System Load Shape, or NSLS. For a given distributor, the NSLS is the distributor's total load shape minus the load of consumers with interval meters that have their hourly usage recorded. Most interval-metered consumers are large consumers. The NSLS is widely used as an approximation of the load shape for smaller consumers, and for purposes of the RPP will be used as an approximation of the load shape of RPP consumers. For this calculation, a weighted NSLS will be used.

The value of M in Equation 1 is therefore the cost at market price of the total demand of the RPP consumers, computed using the weighted average NSLS. The computation will be performed using the production cost model's forecast of hourly prices multiplied by the forecast of hourly demand of RPP consumers. The forecast of hourly demand is obtained by applying the NSLS to the total demand forecast.

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 dollar amount that the prescribed generators would receive under the Market Rules (quantity B in Equation 1) is approximated by their hourly generation multiplied by the Ontario market prices during those hours.[6] Forecasts of both of these variables are available from the production cost model.

[6] Generators are actually paid by the IESO on the basis of five-minute market clearing prices.

For the purpose of setting the RPP price and monitoring variances from it, this calculation produces a monthly aggregated forecast of payments under the Market Rules for generation from prescribed generators.

The amount paid to the prescribed generators (quantity A in Equation 1) will be determined by the regulated rate established by either the Government or the Board as outlined in legislation. The production cost model will provide forecasts of the outputs of the prescribed generators, or, if production schedules are included as part of the regulation, then this schedule will be used in the calculation. It is expected that the price for such generation will not vary over time within a year, since these generators are expected to operate as base load capacity. Quantity B can therefore be forecasted by calculating the average price per MWh for the prescribed generators times their total output per month in MWh. If the regulated price for the prescribed generators is a more complex formula than that, Quantity B will be forecast using the output of the production cost model. The model's outputs will allow forecasts of the costs in whatever form the regulation takes.

Cost Adjustment Term for NUGs

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

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

The amount that the NUGs would receive under the Market Rules, quantity D in Equation 1, is their hourly production times the hourly energy price. These quantities are available from the production cost model as an aggregate for the NUGs as a whole.

The amount that the NUGs receive under their contracts with OEFC, quantity C in Equation 1, is not publicly available information, although it is known that most of the contracts provide for on-peak and off-peak prices. The Board has obtained from the agency responsible for administering the NUG contracts (currently OEFC) a forecast of average on-peak and off-peak prices for these generators and average output on a monthly basis.

Cost Adjustment Term for Renewable Generation Under Output-Based Contracts with the OPA

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

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

Quantities E and F in the above formula refer to generators paid by the OPA under contracts related to output. Generators in this category are renewable generators contracted under the recent renewables RFP.

Computing the amount that would be payable to these generators under the Market Rules, quantity F in Equation 1, requires knowing the quantity of electricity generated per hour and the hourly market price. The quantity of electricity generated in turn is a function of the size and type of the generator. The size, generation type, and location of the successful projects, under the renewables RFP, have been announced by the Ministry of Energy. The production cost model will produce forecasts of their hourly output, drawing on this information and on available information on the technical capability of these types of generators (wind, biomass, small hydro) and wind regimes in Ontario. Together, this information allows calculation of the contribution of renewable resources to quantity F.

Computing the contribution of renewables to quantity E in Equation 1 requires information on the prices they will receive from the OPA. Although the prices for each project are not publicly available, the structure of the prices was specified in the RFP documents. Each generator selected under the renewable RFP will receive a fixed payment for each unit of electricity generated, with a part of the payment also subject to an escalation factor. The amount per MWh is therefore fixed by contract. This price will not be a function of the time of generation, so the contribution of the renewables to quantity E will simply be the total generation from these resources times the average price.

The Board will need to obtain from the OPA information at an appropriate level of detail for purposes of enabling the Board to forecast quantities E and F in Equation 1.

Cost Adjustment Term for Other Contracts with the OPA

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

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

Under the 2500 MW RFP, there will be two kinds of resources under contract to the OPA whose costs will be included in G. The first kind is conventional generation, where the payment from the OPA will relate to the generator's capacity costs. The second kind is demand side management or demand response contracts. Each is treated separately below.

Conventional Generation

The contribution of conventional generation under contract to the OPA to quantity G in Equation 1 depends on the technical capability of the generation, on market conditions, and on their contracts with the OPA. Under the contracts as specified in the RFP, the generators receive both market-based compensation and contractual compensation.

Only the contractual compensation contributes to quantity G. The market-based compensation is included in quantity M of Equation 1 by including them in the production cost model as the successful projects and their schedule for operation becomes known. The amount and scheduling of the output of these generators will be part of the supply in the model, and will be priced at the market price, on the assumption that the generators offer it to the IESO at their incremental costs. Their contracts provide strong incentives to follow that strategy.

The contractual component, which is included in quantity G, is an amount determined by contract and dependent on the cost and technical characteristics of the generator and on electricity market conditions. Each generator has submitted, as part of its bid, technical information that will allow determination of when the generator should be able to cover its variable costs (fuel and variable operating costs) from the market at the current price. It is deemed to run at all such times. The contractual payment to the generator is adjusted based on the net market revenues it is deemed to have earned during the times it is deemed to run. The contractual payment, called the contingent support payment, is set to provide the generators with the contractual rate of return, after their market revenues have been taken into account. These contractual payments, in aggregate, are the contribution of conventional generation to quantity G in Equation 1.

The Board will need to obtain from the OPA information at an appropriate level of detail for purposes of enabling the Board to forecast the contribution of contracted conventional generation to quantity G in Equation 1. With this and other information, the Board will be able to forecast the contribution of the conventional generation under contract to the OPA to quantity G in Equation 1.

Other Procurement Contracts

The nature and terms of the OPA's other procurement contracts, which may include demand-side management and demand response contracts, is currently unknown.

The amounts paid by the OPA for these other procurement contracts must be forecast as accurately as reasonable given information that is available from public sources as well as information provided to the Board by the OPA. The OPA will likely provide information on the total amount under contract for demand-side management. That will be the contribution of demand management to quantity G in the above formula.

Demand response payments are given to specific market participants when they agree to reduce their demand at specific times. Since the OPA cannot know in advance when such demand response will be required, it cannot provide advance information on the totals. Such demand responses are only required, however, at times of tight supply. The production cost model will show how frequent and how severe such periods of tight supply are likely to be. With these results and information on the costs of demand response, the Board will estimate the contribution of demand response contracts to quantity G in the above formula.

Cost for OPA Variance Account

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

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

The OPA will incur direct costs to carry the RPP-related variance account. At a minimum, the OPA must pay interest on any unfavorable variances. Interest costs can be forecast using the forecast of variance over the year and an assumption of the interest rates the OPA would pay, given its credit rating.

At this time, it is not known whether the OPA will allocate any specific operating costs to the administration of its RPP-related variance account. As such information becomes available, any such direct charges can be added to the calculation of quantity H.

Total RPP Supply Cost

The total RPP supply cost will be calculated as the cost of the supply needed to meet the demand from RPP consumers, determined using Equation 1.

3. METHODOLOGY AND TIMING FOR SETTING RPP PRICES

Introduction

The diagram in Chapter 1 indicates that setting the base RPP prices integrates two price components. The larger of the components is forward-looking and is based on a forecast of the RPP supply costs, which will be calculated as detailed in Chapter 2 of this Manual. The smaller component is backward-looking, and is set to recover the accumulated variance in the OPA variance account. These two components are then added together to produce the average RPP price, which is referred to as RPA. This chapter explains the processes for calculating and integrating these two components of the base RPP prices. The chapter also describes the process and methodology for setting the tiered prices and seasonal price tiers for consumers with conventional meters, and time-of-use pricing periods (on-peak, off-peak and mid-peak) for consumers with eligible time-of-use (or "smart") meters.

The contents of this chapter are:

- Timing for RPP price setting
- Setting the price component to recover the RPP supply costs
- Setting the price component to true up the RPP supply cost variance
- Setting the average RPP price
- Setting the prices for RPP consumers with conventional meters
- Setting the prices and times of application for RPP consumers with eligible time-of-use meters
- Price true ups for extraordinary circumstances

Timing for RPP Price Setting

The initial RPP prices will be set to be effective on the first term commencement date. There will be no change in those initial prices until at least the second term commencement date, which will be no less than 12 months later.

After the second term commencement date, price resetting is expected to be considered for implementation every six months. The price resetting will consider whether price changes are needed to recover forecast RPP supply costs over the next 12 months and whether price changes are needed to recover the accumulated variance in the OPA variance account.

Setting the Price Component to Recover the RPP Supply Cost

The first step in the computation of the RPP price is the computation of the forecast RPP supply cost, as described in Chapter 2. The average RPP supply cost is simply the total forecast RPP supply cost for the forecast year divided by the total forecast energy demand for RPP consumers for the year. This price component is not set at the average RPP supply cost, however, it is adjusted to take account of random effects on the costs.

The actual RPP supply cost is subject to random variation from a number of factors. These factors include, among others, the availability of generation from the prescribed generators[7], the availability of generation from resources under contract to the OPA, the level of demand from consumers taking RPP supply (which varies with the weather), and the load shape of that demand.

By their nature, the probability distributions of some of these variables are asymmetric. For example, if the assumed capacity factor of a generator is 80%, then there is more possible downside (to 0%) than upside (to 100%). Some other variables have similarly skewed distributions.

Probabilistic modeling of the variance of actual from forecast RPP supply cost shows that there is a higher probability that the actual RPP supply cost will be above its expected value than below it. In order to reduce the probability that this variance will trigger the need for multiple mid-plan price adjustments, this component of the RPP price is chosen at a level that will make the cumulative expected value of the variance over the 12 months after the price resetting equal to zero. This computation will be performed using a probabilistic simulation of the system (Monte Carlo technique) to determine the size of the variance given assumptions about the level of price and the distributions of the variables that drive market price determination.

The result of this computation is a price that will make zero the expected value of the variance of the cumulative *actual* RPP supply cost from the cumulative *forecast* of RPP supply cost. That price is then the component of the RPP price

[7] This refers to OPG generation assets that are subject to Government regulation.

intended to recover the forecast RPP supply cost over the RPP price-setting period. This price ensures that the forecast of the cumulative variance over the 12 months after the price is set will be zero.

Setting the Price Component to True Up RPP Supply Cost Variance

The RPP supply cost variance is the difference between the actual RPP supply cost in a year and the amount collected from RPP consumers during that year. This amount is accumulated and held by the OPA in a variance account, and is tracked and monitored monthly as described in Chapter 4 of this Manual.

The variance is forecast for each month of the RPP year. At the end of each month there will therefore be a forecast and an actual variance amount. The difference between these is called the deviation (or unexpected variance) for the month.

For an RPP year, the forecast cumulative variance is zero because the RPP price is designed to make it so. For any shorter period, the forecast cumulative variance will not be zero, since the variance is expected to display a seasonal pattern, with consumer debit variances expected to accumulate in the peak (winter and summer) seasons and consumer credit variances expected to accumulate in the shoulder (spring and fall) seasons. Only an observation that there is an unexpected cumulative consumer credit or debit balance at the time of a price resetting means that the price should be trued up to recover that deviation. The relevant amount for the true up is not the *actual* accumulated variance, but the accumulated deviation of the *actual* variance from the *expected* variance. In other words, the amount to be trued up is the *unexpected* variance, or deviation.

This accumulated deviation is to be recovered over the 12 months following the date of the price setting. The component of the RPP price for recovery of this accumulated deviation is therefore the total of the accumulated deviation divided by the forecast demand from RPP consumers over the succeeding 12 months.

Setting the Average RPP Price

The average RPP price will be the sum of these two components:

1. The *prospective* recovery of the forecast RPP supply cost and

2. The *retrospective* recovery of the cumulative deviation or *unexpected* variance.

This average RPP price is denoted as "RPA".

The next steps in the price-setting process determine the prices (tiers, for those with conventional meters; time of use prices, for those with eligible time-of-use meters) to be charged to each of these groups of consumers.

Setting the Prices for RPP Consumers with Conventional Meters

The final step in setting the price for RPP consumers with conventional meters is determining the tier structure of the RPP price. The tier structure includes both the levels of the prices in the two tiers — $RPCM_{T1}$ (the price at or below the tier) and $RPCM_{T2}$ (the price above the tier) — and the threshold level of consumption at which the consumers' price will move from the lower to the higher tier.

The tier prices, $RPCM_{T1}$ and $RPCM_{T2}$, will be the same for all RPP consumers. However, the tier thresholds will not necessarily be the same at all times, as stated in section 3.3.2 of the SSS code. This Manual will discuss the methodology for both decisions. The first calculation will set the prices for all RPP consumers with conventional meters, assuming that the tier thresholds are the same for all consumers (as they will be until October 31, 2005). Then the Manual will discuss the choice of tier thresholds on and after November 1, 2005.

The tier prices must be calculated so that the expected average price, calculated on a "tier load weighted" basis, equals the average RPP price, RPA.

The current tier prices for low volume and designated consumers, which $RPCM_{T1}$ and $RPCM_{T2}$ will replace, are 4.7 cents per kWh for consumption at or below 750 kWh per month, and at 5.5 cents per kWh for consumption above that amount per month, for each consumer.

Given the tier threshold, the amount of electricity expected to be priced at each tier can be estimated. For that estimation, the Board will use information showing how much electricity consumers purchase in each month at each of the tiers. That calculation will assume that the tier thresholds are the same for all RPP consumers.

The Board will then calculate the tier prices by maintaining the existing ratio between the upper and lower tier prices (in other words, the existing ratio of 4.7

cents to 5.5 cents). For example, if RPA is calculated to be 5.6 cents per kWh, then the forecast weighted average price for RPP consumers with conventional meters must be 5.6 cents per kWh. Assuming that the current ratio of the prices is maintained, and that about half of the total demand from RPP consumers is taken at each tier level, the resulting prices would set $RPCM_{T1}$ at 5.2 cents per kWh and $RPCM_{T2}$ at 6.0 cents per kWh. For the actual calculation, the Board will use information about monthly consumption volumes.

This Manual now addresses the threshold for *residential* consumers. The SSS Code has some specific provisions for the tier thresholds. It states in section 3.3.2 (c) that the threshold for residential consumers will be 750 kWh per month (its present level) until October 31, 2005. After that, the threshold will change seasonally, with two six-month seasons starting on November 1 and May 1. For *non-residential* consumers, the SSS Code (section 3.3.2 (d)) states that the threshold is fixed at 750 kWh per month until at least the second term commencement date, but the Board may vary it after that date.

Adjustment of the threshold for *residential* consumers during the heating season could help alleviate the potential for some consumers with electric space heating to be paying high average prices. In the winter season, defined as November through April, the tier threshold will be set at a higher amount per month. In the rest of the year, the tier threshold will be lower by an amount that will keep the average annual RPP price for residential consumers equal to the average RPP price, RPA. Keeping the average price for residential consumers at RPA avoids cross-subsidies with consumers whose thresholds are not adjusted on a seasonal basis.

Considerations in the choice of thresholds are the impact of the threshold on consumers and the need to maintain the average RPP price for residential consumers at the level of the average RPP price as determined in accordance with this chapter.

Average residential electricity consumption in Ontario is about 10,000 kWh per year per household, or about 830 kWh per month. On average, therefore, residential consumers currently take some of their supply at the higher price tier in each month. Given seasonal consumption patterns, however, in shoulder months the majority of residential consumers do not exceed the 750 kWh threshold. Residential consumers using electric space conditioning – heating or cooling – will likely take a larger fraction of their supply at the higher tier in the space conditioning months.

The tier thresholds for residential consumers are set at 1000 kWh per month in the winter (November 1 to April 30) season and 600 kWh per month in the summer (May 1 to October 31) season. These thresholds were selected based on information on the amount of electricity that consumers use in each of the heating and non-heating months. The lower summer tier threshold will take effect in the second year of the RPP; the threshold will remain at 750 kWh until October 31, 2005.

Setting the Prices for RPP Consumers with Eligible Time-of-use Meters

This section explains the methodology for computing the prices for RPP consumers with eligible time-of-use meters. Time-of-use pricing will be optional (at the discretion of the distributor) until the second term commencement date. For the initial RPP term, an RPP consumer with an eligible time-of-use meter will thus be charged time-of-use RPP prices only where the consumer's distributor has elected to make that pricing available. An RPP consumer with an eligible time-of-use meter will continue to be charged conventional meter prices until the second term commencement date if the consumer is served by a distributor that has not elected to make time-of-use pricing available during the initial RPP term.

The prices for consumers with eligible time-of-use meters will be set to make the forecast average price charged to them equal to RPA, the average RPP price. The basic methodology for determining the time of use prices, the values of $RPEM_{OFF}$ (price during an off-peak period), $RPEM_{MID}$ (price during a mid-peak period), and $RPEM_{ON}$ (price during an on-peak period) will be to use data from the forecast cost of RPP supply and the forecast demand for such consumers to determine a set of prices that reflects their supply cost and that averages to RPA.

Prices for consumers with eligible time-of-use meters (time-of-use prices, or TOU prices) will differ according to the season and time of day. The level of these prices is closely connected to the times when these prices apply because the cost of supplying electricity varies according to when it is supplied.

Objectives and Choices

Setting the prices for consumers with eligible time-of-use meters requires more steps and more decisions than for consumers with conventional meters. The complexity arises from the requirement to set more prices and the time periods when these prices will apply.

One of the objectives of having time-of-use meters is to give consumers more precise price signals and incentives to respond to those price signals. Consumers with eligible time-of-use meters will see prices that differ during the day,[8] reflecting relative costs of generation at different times and allowing consumers to benefit by changing their consumption in response. Prices charged to such consumers will be fixed in advance, as they are for consumers with conventional meters, in order to limit their exposure to supply price volatility.

The objectives for the pricing system for consumers with eligible time-of-use meters include:

- Set prices to recover the full cost of RPP supply; that is, the price structure must, on a forecast basis, recover all the RPP supply costs from the consumers who pay the prices;
- Set the price structure to reflect RPP costs; that is, the prices should reflect the differences in cost of supply at different times of the day and year;
- Set prices to give consumers incentives and opportunities to reduce their electricity bills by shifting their time of electricity use; and
- Create a price structure that is easily understood by consumers.

These objectives guide the choices to be made to determine the prices. Some choices have been made and are reflected in the SSS Code. The most important of these are that there will be two seasons and three price levels. The remaining choices include

- The times of day at which the three price levels ($RPEM_{OFF}$, $RPEM_{MID}$, and $RPEM_{ON}$) will be applied:
  - Whether the times will differ in different *seasons* (and if so, how)
  - Whether the times will differ by *day* of the week (weekday vs. weekend)
- The three price levels ($RPEM_{OFF}$, $RPEM_{MID}$, and $RPEM_{ON}$)

Times of Application of Prices

The times of application of the prices should be chosen to further the objective of making the prices reflect the changes in supply costs over time in the Ontario electricity market. Since the prices are based on forecasts, the pattern of seasonal prices can also be based on forecasts. Figure 4 below shows the forecast of

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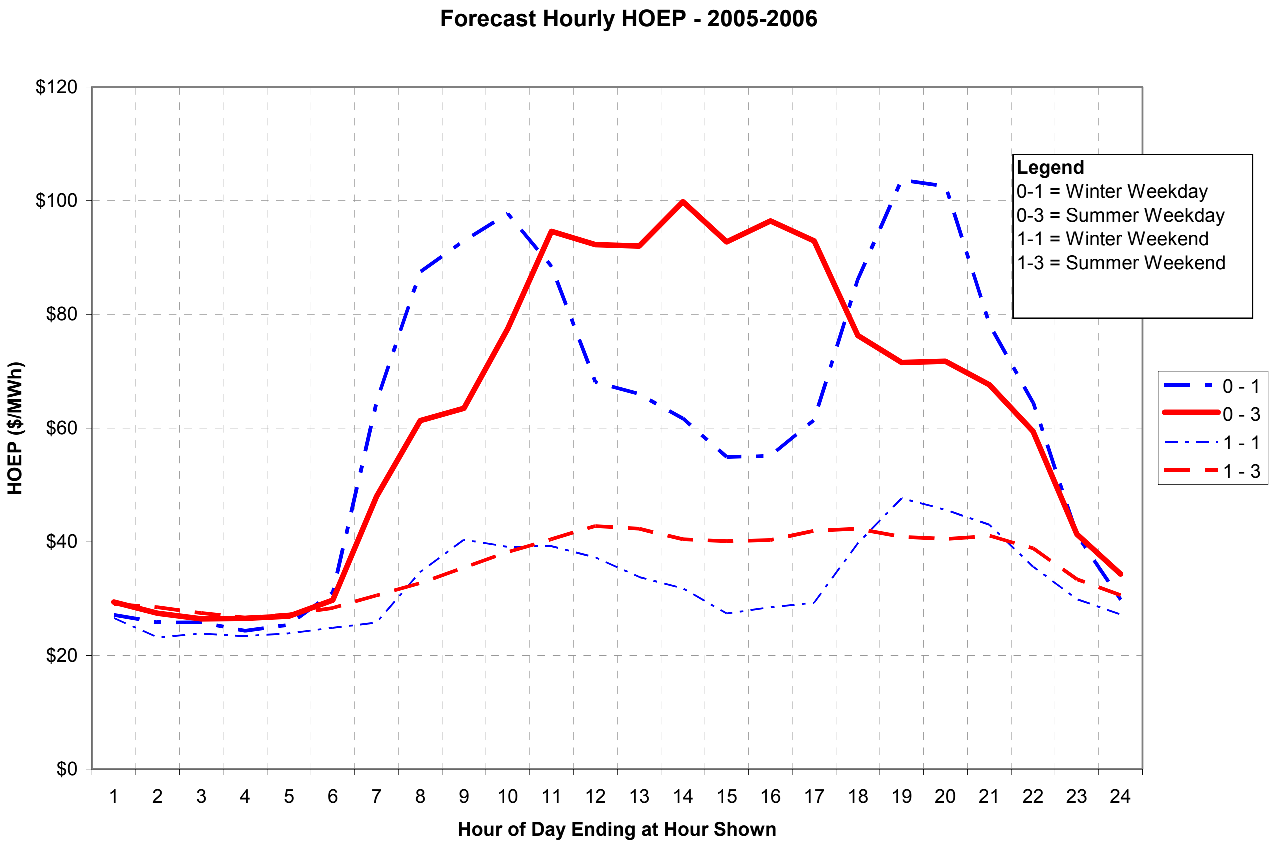
[8] As noted above, until the second term commencement date this will only apply to consumers served by a distributor that has elected to implement TOU prices.

hourly HOEP, by season, for the first year of the RPP. Prices are the forecast HOEP for the hour of day ending at the hour shown on the horizontal axis. The price points are plotted in the middle of the hourly intervals shown.

Figure 4: Forecast Seasonal HOEP



Source: Navigant Consulting

The chart shows some consistency and some difference in the daily patterns of forecast prices in the two seasons.

Winter prices show a pronounced daily peak in the early evening hours, corresponding to residential and commercial lighting and space heating uses, and to residential appliance use. The winter evening peak price lasts from roughly 5 p.m. to 10 p.m. There is an almost equal peak period in the early morning hours, again reflecting commercial and residential lighting and space heating, and residential appliance use. The morning peak period lasts from about 7 a.m. to 11 a.m. While the highest prices in the morning are not as high as the highest evening peak prices, they are noticeably higher than those in the middle of the day. Winter therefore shows a noticeable daily double peak pattern.

In the *summer*, prices start to rise at about the same time as they do in the winter, about 7 a.m., but the top peak period is spread out over the afternoon, lasting from about 11 a.m. to 4 p.m. This corresponds to residential and commercial air-conditioning use on the hottest summer days. Accordingly, summer has a single daily peak period. The summer peak prices are close to those of the winter peak, though the averages are somewhat lower.

The pattern of off-peak prices is quite stable for both seasons. Demand falls off sharply after about 11 p.m., and picks up sharply at about 7 a.m.

These data also distinguish between *weekdays, weekends and holidays*. Weekends and holidays have much lower and much flatter forecast hourly prices because the overall demand is lower and the prices are therefore lower. Because the prices tend to be lower for whole weekends, the entire weekend can be defined as an off-peak period.

The choice of periods for different prices should reflect these patterns of market price, but need not directly replicate them. A price that varies too frequently would jeopardize the RPP goal of price stability.

The data support a three-price pattern. Figure 4 above shows a period of distinctly higher prices in the winter morning and evening hours than during the rest of the winter day. The peak prices in the summer are close to those of the winter. Figure 4 also shows that prices are lower on summer evenings than summer days. While Figure 4 shows the difference between the summer mid-day hours and the rest of the summer day to be less distinct than the winter patterns, the difference is clearly present. The data indicate a consistent pattern of low, medium and high prices at specific times of the day and season.

The next issue is exactly what times to choose to apply the three prices. All of the weekday prices ramp up rapidly at about 7 a.m., making that time the natural choice for the end of the off-peak period in both summer and winter. Prices ramp down sharply at about 10 p.m. to 11 p.m. in both winter and summer. Setting the beginning of the off-peak period at 10 p.m. (as opposed to 11 p.m.) will give consumers more opportunity to respond to the higher prices by switching consumption to a lower-priced period while they are still active during the day.

These considerations mean that the peak periods (both mid-peak and on-peak) should be from 7 a.m. to 10 p.m. in both winter and summer. Off-peak weekday periods are therefore from 10 p.m. to midnight and midnight to 7 a.m.

The mid-peak and on-peak periods should reflect the times of distinctly higher prices. Winter has both morning and evening on-peak periods. The morning on-peak period lasts from about 7 a.m. to 11 a.m. or noon, and the evening from 5 p.m. to 8 p.m. or 9 p.m. Prices fall off to the mid-peak levels after 9 p.m., and stay there until they fall again after 10 p.m. or 11 p.m. Reasonable on-peak periods for winter weekdays are therefore 7 a.m. to 11 a.m. and 5 p.m. to 8 p.m.

In the summer, the on-peak period for weekdays is from noon to 5 p.m. The forecast data also show a similar pattern of prices, with a clear price break before and after those times.

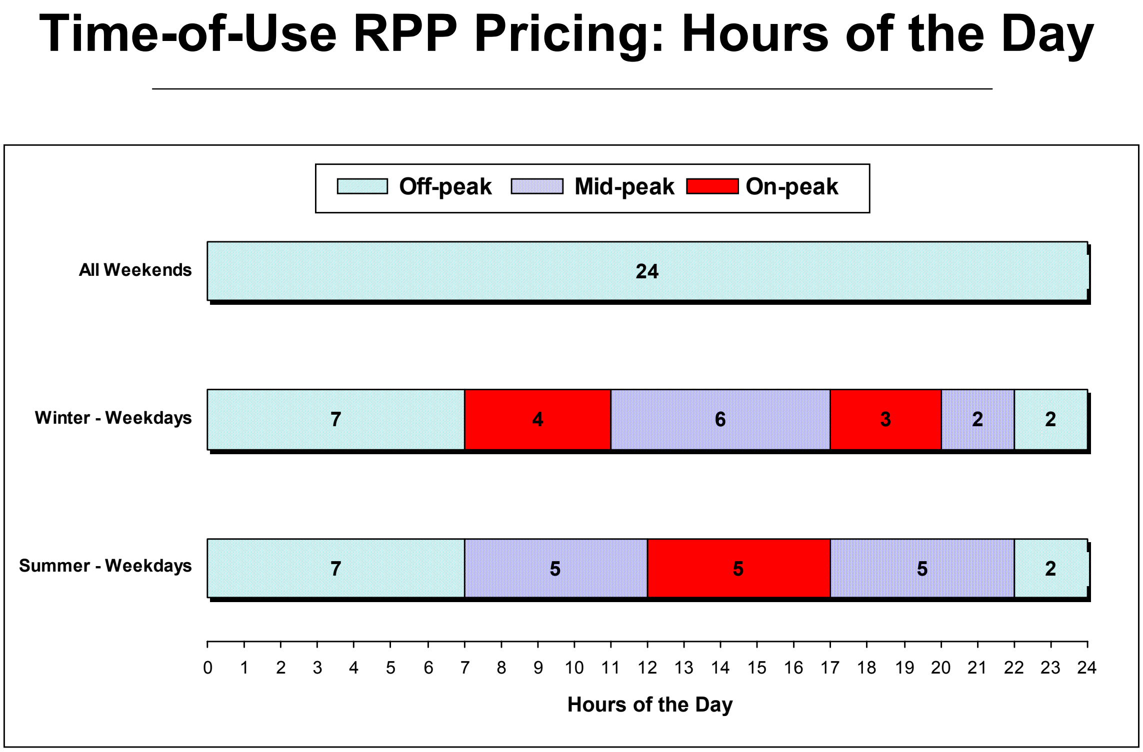
Figure 4 also differentiates between weekday and weekend hours. Weekend hours have much the same daily pattern as weekday hours, except that prices tend to be flatter throughout the period from 7 a.m. to 10 p.m. Both the actual and forecast data show the highest weekend prices to be well below those of the weekday mid-peak periods. Giving weekends and holidays only off-peak prices would better reflect their cost conditions.

Taking these factors into consideration, the time periods for price application are defined as follows and as illustrated in Figure 5 below:

- *Off-peak* period (priced at $RPEM_{OFF}$):
    - *Winter and summer weekdays*: 10 p.m. to midnight and midnight to 7 a.m.
    - *Winter and summer weekends and holidays*[9]: 24 hours (all day)
- *Mid-peak* period (priced at $RPEM_{MID}$)
    - *Winter weekdays (November 1 to April 30)*: 11 a.m. to 5 p.m. and 8 p.m. to 10 p.m.
    - *Summer weekdays (May 1 to October 31)*: 7 a.m. to 11 a.m. and 5 p.m. to 10 p.m.
- *On-peak* period (priced at $RPEM_{ON}$)
    - *Winter weekdays*: 7 a.m. to 11 a.m. and 5 p.m. to 8 p.m.
    - *Summer weekdays*: 11 a.m. to 5 p.m.

[9] For this purpose, a "holiday" is a statutory holiday in Ontario.

Figure 5: Times of Price Application



Establishing Prices

A basic requirement for TOU prices is that they must recover all of the expected costs of the supply; that is, they must average to RPA. They also should reflect the relative costs during the periods when they are being applied. In addition, the load shape of these consumers – and therefore the cost of supplying them – will change as they react to the prices themselves; the higher the differential between each of the on-peak, mid-peak and off-peak prices, the more consumers can be expected to shift electricity usage.

For the calculations necessary to arrive at the initial TOU prices, it will be assumed that consumers with eligible time-of-use meters and those with conventional meters have the same load profile, which is given by the net system load shape (NSLS) for all RPP consumers as used for the calculations in Chapter 2.[10] For the initial calculations, therefore, the average price for time-of-use meters will be RPA. In later calculations, when enough data are available from time-of-

[10] This assumption can be changed for later calculations, when experience with time-of-use meters provides better data on the load shape of consumers with time-of-use meters and on how their load shape changes in response to time-of-use pricing.

use meters to construct a revised load shape, the calculation will consider separately the load shapes and costs of consumers with eligible time-of-use meters.

To begin the calculation, the load profile of time-of-use meter consumers is used to calculate the supply cost for those consumers. This amount is analogous to the RPP supply cost of total demand of participating RPP consumers or quantity M in Equation 1 of Chapter 2. Then this amount is adjusted by the other components of Equation 1. This amount is the RPP supply cost for consumers with eligible time-of-use meters. It is the amount that must be recovered by the three prices.

The three prices must then be set to recover that amount.[11] The key to setting these prices is that they should reflect cost at their times of application. TOU prices are based on forecasts, as are the prices for consumers with conventional meters. To determine TOU prices, the production cost model price forecast will be analyzed to determine average price levels during the different times of application referred to in Figure 5. Then the process can set prices or price ratios to reflect costs. The forecast data show that the off-peak HOEPs are close to each other and stable in all seasons. The *off-peak* price will be set at approximately the level of the average forecast off-peak price for both seasons of the year. Using that level, and the assumed load shape, gives the portion of the total supply cost from the off-peak prices. Then the *mid-peak* prices can be set similarly (again reflecting forecast mid-peak prices that are close to each other and relatively stable in all seasons, as they seem likely to be), leaving the *on-peak* prices to be determined.

After any two of the prices are set, the third (on-peak) price is determined by the need for the forecast prices to fully recover the costs of supply. It is calculated as the price that will meet the forecast supply costs, given the assumed load shape. The price so determined may or may not be fully reflective of the average forecast price in the production cost model during the on-peak hours. Some adjustment may be needed to the other prices to produce a set of three prices that meets the criteria of recovering the forecast supply cost and of reflecting the average forecast prices during the hours of application of the prices.

[11] In the initial calculations, the prices will be set so that their load-weighted average is equal to RPA.

The ratio of the prices will therefore be set in a way that reflects the relative forecast costs from the production cost model for the year for which the prices are being set.

An analysis of existing forecast data suggests that these prices would occur in the ratio of roughly 1:2:3. This is the relationship that appears in the average forecast prices from the existing forecasts. That is, the forecast price at the mid-peak times, corresponding to $RPEM_{MID}$, is roughly twice that at the off-peak times, corresponding to $RPEM_{OFF}$, and the forecast price at on-peak times, corresponding to $RPEM_{ON}$, is roughly three times $RPEM_{OFF}$.

Price True Ups for Extraordinary Circumstances

Under some extraordinary circumstances, large unexpected variances (deviations) could accumulate in a short time. This could occur as a result of some major unanticipated event, such as a prolonged unexpected nuclear outage affecting more than one nuclear unit. As described in Chapter 4 of this Manual, deviations of actual from forecast variances will be tracked and monitored monthly. It might be desirable, under such extraordinary circumstances, to take prompt action to bring prices back towards cost to avoid the possibility of accruing undesirably large deviations and, as a result, unusually high price adjustments at the next scheduled RPP price adjustment date.

In general, it would be expected that such action would not be taken on the basis of one or two months' experience, but rather would be considered on a quarterly basis. Quarterly analysis smoothes the more extreme variations of monthly results, and should therefore avoid making changes in reaction to an extreme that does not recur.

For similar reasons, an interim true up of this kind should only occur when there has been an extraordinary accumulation of deviations from the expected variance, as indicated by the deviation exceeding a trigger value. Considerations in setting the trigger value include the impact on the consumer bill and the probability of that high a deviation occurring.

With roughly 4 million RPP consumers, the average cost per customer of a $40 million deviation is about $10. That would have a bill impact of under $1 per month, if collected over 12 months. Variance modeling shows that a deviation of about $40 million a month occurs less than 10% of the time. Choosing a trigger value of $160 million would produce a per customer impact of $40, and a bill impact of about $3.40 per month. Variance modeling suggests that random events would produce a deviation of that magnitude in a single quarter less frequently than once in five years.

The trigger value is therefore set at $160 million. When an *unexpected* variance (or deviation) of $160 million or more accumulates over a quarter that does not conclude with a scheduled semi-annual true up and rebasing, a price true up will automatically be implemented to begin to recover that variance.

The price true up will be calculated in the same way as at a regular semi-annual adjustment point, as the total deviation divided by the total forecast RPP demand over the next 12 months.

This extraordinary case is the only time that a change in the RPP price is based solely on the need to recover accumulated deviations of the variance from the expected variance (i.e., only retrospective). All ordinary or scheduled RPP price adjustments are based on recovery of both the forecast RPP supply cost and the past accumulated deviations (i.e., both retrospective and prospective).

4. Methodology and Timing for Variance Tracking

Introduction

This chapter sets out the methodology and timing for tracking and monitoring the monthly balances[12] in the OPA variance account, carried for RPP consumers. The monthly variance balance held by the OPA is the difference between the actual RPP supply cost for the month and the revenues collected from RPP consumers for that month.

The actual monthly variance account balance will be compared against the expected monthly variance account balance. This chapter describes the methodology and timing for the calculation of the forecast variance and for tracking deviations of actual from forecast variance. Chapter 3 describes the uses of this information for price rebasing and price true ups.

Contents of this chapter are:

- Monthly Variances
- Variance Forecasting
- Variance Monitoring
- Frequency of Variance Monitoring

Monthly Variances

For consumers with and without eligible time-of-use meters, the RPP prices are set in advance for an entire forecast year. The prices reflect a forecast of average RPP supply cost for the forecast year, adjusted to collect any outstanding variance balance at the beginning of the period and to bring the expected annual cumulative variance balance to zero.

The RPP supply cost in each month can be expected to vary in a systematic way from the average monthly RPP supply cost. This is because both price and demand conditions vary over the year. For example, in the shoulder months, market prices will be lower than the annual average, producing a monthly RPP supply cost that is lower than its annual average. In the peak demand months,

[12] This discussion is in terms of monthly variances because that is the frequency with which the OPA is expected to accumulate variance data.

the market can be expected to produce a monthly RPP supply cost that is higher than its annual average.

These considerations lead naturally to the expectation that, in the low-price months, a “consumer credit” balance can be expected to accumulate in the variance account; in the high-price months, a “consumer debit” balance can be expected to accumulate in the variance account. Although the average RPP price or RPA is chosen to produce a zero expected value of the cumulative variance over the year, the expected value of the variance in each month is not zero. The difference between the forecast monthly variance and the actual monthly variance is the monthly deviation.

For the purpose of considering changes in the RPP price, the size of the variance must be monitored. Variances must be trued up so that the actual cost of RPP supply is recovered over time, as required by the Act. However, in monitoring the monthly variance, the quantity to be monitored is not the actual variance itself but its deviation from the expected variance for that month and the deviation of the cumulative balance of the variance account from its expected value in that month. Monitoring variances therefore requires a methodology for computing expected monthly variances.

Variance Forecasting

The methodology for setting RPA requires modeling variances of the actual RPP supply cost from the forecast RPP supply cost, in order to determine RPP prices that set the expected variance to zero. For that purpose, a probabilistic model is constructed which models the events that can produce variances from the forecast RPP supply cost, given assumptions about the probability distribution of the key driving variables. The model results are then used to establish the expected value of the variance. This variance model will be the basis for the forecast of expected monthly variances.

A monthly variance forecast will be produced each time that RPP prices are reset because variance modeling will be done at that time. At and after the second term commencement date, this is expected to be undertaken every six months. The variance forecast will use monthly forecasts of the variables driving the monthly RPP supply cost. These variables include electricity demand and generation availability. These factors will be taken at their values from the production cost model, either as inputs to or outputs from that model. The variance model also takes account of the historical volatility of HOEP. These values are then used to produce forecasts of the monthly variance.

Variance Monitoring

Two variance totals will be calculated and monitored. The first is the cumulative actual variance, as seen in the variance account of the OPA. That amount is the cumulative difference between the actual RPP supply cost and the revenues collected from RPP consumers. It is the amount that must ultimately be collected from consumers, if it is a consumer debit, or paid to them if it is a consumer credit.

However, as noted above, recovering that cumulative actual variance amount may not require any additional action. If the cumulative actual variance in any month is the amount expected in that month, it will be expected to be offset by variances in the opposite direction in the coming months so that it will be zero by the end of twelve months from the time of price resetting.

For considering true ups the relevant amount is therefore the difference between the expected and the actual variance, which is the deviation. The forecast monthly variance is subtracted from the actual monthly variance in each month to get the monthly deviation. The deviation is also accumulated into a quarterly total. The monthly deviation of actual from forecast variance is monitored for information and to understand trends. The quarterly cumulative deviation of actual from expected monthly variance is monitored for its potential to trigger an extraordinary true up, as described in Chapter 3.

The total cumulative deviation of the actual RPP supply cost variance from the forecast RPP supply cost variance is the amount to be trued up, as described in Chapter 3 of this Manual.

Frequency of Variance Monitoring

The process described above will occur monthly. The variance will be available on a monthly basis from the OPA, and the Board will perform the steps listed in this chapter to monitor its deviation from the forecast for that month.

Although the monitoring is monthly, the decision on price resetting and true ups, as described in Chapter 3 of this Manual, is expected to be taken every six months. There is also provision for a true up as an extraordinary event if the quarterly variance exceeds a trigger level. However, the monthly variance monitoring data will generally be used to inform the Board as to the current prospects for coming events.

5. Timing for RPP Price Adjustments or Price Structure Changes

Introduction

This chapter sets out how long in advance new RPP prices or changes in RPP price structure will be determined by the Board prior to the date on which the new prices or structure are to come into effect. This reflects the period of time that distributors will have to implement price or structure changes and can be considered as a notification period to distributors. The time periods noted below are consistent with section 3.8 of the SSS Code, which contains provisions that require distributors to notify RPP consumers of RPP-related changes.

New RPP prices will generally be computed at six-month intervals and will be the result of an integrated consideration of re-basing and true ups. Price changes will become effective at the beginning of a calendar month.

Contents of this chapter are:
- Timing of Notification of Price or Price Structure Change
- Timing of Implementation by Distributors

Timing of Notification of Price or Price Structure Change

Most changes in the RPP will change only the RPP prices. For such changes, distributors require a minimum of 30 days' lead time before customers can be billed based on the new RPP price. Since distributors do not start to bill customers at the new price until about 15 days after its implementation, the 30-day distributor lead time is achieved by setting the new prices at least 15 days before the beginning of the month in which the new prices are to be implemented. New prices will therefore be set (and distributors will thus be informed) at least 15 days before those new prices are to be implemented by distributors. This applies to changes in any RPP price, namely, to changes to any of $RPCM_{T1}$, $RPCM_{T2}$, $RPEM_{OFF}$, $RPEM_{MID}$, and $RPEM_{ON}$. This also applies to price changes that are intended to true up prices as a result of extraordinary circumstances, as described in Chapter 3.

Changes to the RPP price structure include changes to tier thresholds and any other change affecting an RPP element other than prices. For changes to the RPP price structure, distributors require 90 days of lead time, or 75 days before the changes are to be implemented. Therefore, structural changes will be determined by the Board (and distributors will thus be informed) at least 75 days before their implementation date.

Timing of Implementation by Distributors

Distributors will charge RPP consumers based on new RPP prices or a new RPP price structure for consumption on and after the first day of the month of implementation. For most RPP consumers, the first day of the month will not correspond to a meter reading, so the SSS Code permits distributors to pro-rate for the billing period within which the price or price structure change takes effect.

6. METHODOLOGY FOR DETERMINING FINAL VARIANCE SETTLEMENT AMOUNTS

Introduction

This chapter explains the methodology to be used by distributors to compute final settlement variance amounts for RPP consumers leaving the regulated price plan. This is the methodology referred to in section 3.7.1 of the SSS Code.

As shown in Figure 1 of Chapter 1, the OPA will carry a variance account representing the accumulated difference between the actual RPP supply cost and the revenues collected from RPP consumers.[13] Consumers who do not leave the RPP will pay the accumulated variance over the next 12 months through the component of the RPP price that reflects past variances,[14] as described in Chapter 3 of this Manual. However, once consumers leave RPP supply,[15] they no longer pay RPP prices and therefore no longer pay their share of past cumulative variances. For that reason, these consumers will be responsible for a final variance settlement when they leave RPP supply since the RPP price determination assumed that they would have remained on RPP for the full 12 months.

Contents of this chapter are:

- Determination of Variance Amount and Final Variance Settlement Rate
- Final Variance Settlement Amount Calculation

Determination of Variance Amount and Final Variance Settlement Rate

The variance amount that will be the basis for the final variance settlement is the cumulative variance held by the OPA, referred to in Equation 2 below as CV_t. That cumulative total is the total variance of the actual RPP supply cost from the

[13] This difference could be positive (i.e., the consumer would receive a payment or credit) or negative (i.e., the consumer must make a payment). The text is written for the consumer making a payment, but the reverse situation applies equally.

[14] RPP consumers are also responsible for paying the OPA's carrying costs for the variance account. Depending on how those costs are accounted for, the consumer leaving RPP supply could also be responsible for a share of these carrying costs. Equation 2 assumes that such costs will be included in the variance reported by the OPA. If they are not, Equation 2 will be modified accordingly.

[15] That is, move out of Ontario, switch to the spot market option or to a competitive retailer, and may include others as determined by the Board.

revenues collected from RPP consumers. It is therefore the amount that will be collected in the future from consumers remaining on RPP supply. It will be collected from them in the RPP prices they pay after RPP prices have been reset and trued up. When consumers leave RPP supply, they will not be paying RPP prices and therefore will no longer be paying any of that cumulative variance. The amount the individual consumer would be responsible for will therefore be estimated and recovered (or paid) by the distributor at the time of leaving RPP supply.

To facilitate this variance account settlement procedure, the OPA will report monthly to the Board on the accumulated balance in its RPP variance account. The Board will convert that amount into a per kWh variance recovery amount for final settlement by dividing the total accumulated variance by the actual total RPP consumption in the preceding 12 months.

The calculation of this amount is given in Equation 2 below:

Equation 2

$$V_{FS} = CV_t / D_{12},$$

Where V_{FS} = the variance amount for final settlement, per kWh

CV_t = cumulative variance total in the OPA account at the end of month t; and

D_{12} = the total consumption from RPP consumers over the 12 months before (and including) month t.

V_{FS} expresses the cumulative variance on a per unit basis for the most recent 12 months prior to leaving the RPP, and is an approximation of the rate at which any RPP consumer would make payments towards the cumulative variance.

When prices are trued up, the cumulative deviation is collected through RPP prices over the next year from consumers that remain on RPP. The amount per kWh is set as the cumulative variance divided by the forecast of total RPP consumption over the year. The variance settlement for the consumer who leaves RPP supply will similarly represent the total payment that would have been made over the year. Since there is no forecast of that consumer's expected demand over that year, consumption over the previous year is used as an estimate.

Final Variance Settlement Calculation

The final variance settlement process collects an appropriate amount from a consumer leaving RPP supply. The amount to be collected in relation to a given consumer is V_{FS} times that consumer's actual consumption over the preceding 12 months, determined as discussed below.

In general, a distributor will not have a precise total for the consumer's actual consumption over the exact 12-month period before the date on which the consumer leaves RPP supply. Whether from a final meter read or a prorated estimate, the distributor will have final consumption data for the final bill. It may not have a corresponding meter read for a period of exactly 12 months before the final billing date because many distributors read meters on a bi-monthly schedule. However, distributors do retain meter reading history for at least a year, so they do have total metered consumption by the consumer for some previous 12-month period.

In the absence of actual consumption information, a distributor must estimate the consumer's consumption over the previous 12-month period by using the actual meter reading or final estimate data for as much of the period as is available and interpolating to get an estimate of what the meter reading would have been on the date exactly 12 months prior to the final meter read.

This allows for a fair approximation of the actual amount that the consumer would have been responsible to pay had the consumer remained on RPP supply, while not burdening the distributor with the unduly complex data maintenance or computational requirements associated with a more precise determination.

A distributor must collect this final variance settlement amount from each consumer leaving RPP supply under the conditions described in section 3.7.1 of the SSS Code. For this amount then to be properly credited to the OPA variance account, it must be reported to the OPA under procedures to be established by the OPA and IESO.