Board Proposal

Regulated Price Plan for Electricity Consumers

RP-2004-0205

Ontario Energy Board

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1.0 Introduction

Under the *Ontario Energy Board Amendment Act, 2003*, the price payable for the electricity commodity for certain consumers is established by the government. At the present time, low-volume or designated consumers that do not choose an electricity retailer are subject to a tiered pricing structure under which they pay 4.7 cents per kWh for the first 750 kilowatt hours per month of electricity consumed and 5.5 cents per kWh for all additional electricity consumed in the month.

This legislation also contemplates that the commodity price to be paid for electricity will be established by the Ontario Energy Board (the "Board") commencing no later than May 1, 2005. Bill 100 reinforces the Board's mandate by requiring that the Board will develop an annual regulated price plan ("RPP"). Once the RPP is in effect, it will govern the price payable for electricity by consumers that are eligible for the RPP. Eligibility for the RPP will be established by regulation.

This document contains an overview of the Board's progress and process to date in establishing the RPP, a description of the principles and objectives of the RPP, and a proposal for the elements that will make up the RPP. The final section of this document outlines the next steps in the process, and includes an invitation to all stakeholders and the public to provide comment on the RPP elements contained in this document.

1.1 Context for the OEB's RPP Mandate

Until the *Electricity Pricing, Conservation and Supply Act, 2002* went into effect, most consumers that did not have a contract with an electricity retailer paid the wholesale spot market price for electricity. These consumers were referred to as "standard supply service (SSS) consumers". This was an easily administered approach, but did carry some disadvantages such as exposure to market volatility and "after the fact" notification about the price paid for electricity. When high seasonal demand was matched with tight supplies, the relatively high market clearing prices resulted in significant increases in consumers' total electricity bills.

In response, in 2002 the Government introduced the *Electricity Pricing, Conservation and Supply Act, 2002*, which fixed the commodity price for electricity at 4.3 cents per kWh for low volume and designated consumers. For various reasons, this resulted in significant taxpayer liabilities for electricity costs. To address the problem of growing liabilities and to provide incentives to conserve electricity, the new consumption-related "two-tier" price structure was announced in 2003 and implemented on April 1, 2004. It increased the average commodity price for electricity, while retaining the same consumer eligibility criteria (low volume and designated) as the previous 4.3 cent fixed-price structure.

In early 2004, the Electricity Conservation and Supply Task Force established by the Government recommended a future electricity market structure based on a "hybrid" market comprised of market-based, regulated and contract-based supply, with consumer prices to be established accordingly.

In mid-April 2004, the Minister of Energy outlined a vision for Ontario's electricity industry. Central to this vision is a "standard rate plan" that will ensure that residential and small business consumers pay the true cost of electricity over time, but within a stable and predictable price framework. The Minister also stated that the standard rate plan should support conservation, "smart metering" and load shifting initiatives through "time of use" pricing.

In mid-June 2004, the Government introduced Bill 100, which sets out the Board's mandate to develop the RPP. The charge to the Board is to develop a "regulated price plan" that is forward looking, stable and cost-reflective, and that "blends" market, regulated and contract prices. This price "blending" is to take place in such a manner that revenues paid to generators for that proportion of load represented by RPP-eligible consumers are closely matched to the revenues collected from those same consumers. Appendix A contains a more detailed description of the price blending methodology. At the same time, the RPP is to include, if appropriate, elements of tiering, seasonal, or time-of-use factors to encourage the rational and efficient use of electricity.

Other elements of Bill 100 that are relevant to the RPP include the establishment of the Ontario Power Authority (the "OPA") as the entity responsible for, among other things, contracting for electricity supply, as well as the introduction of regulated pricing for designated facilities owned by Ontario Power Generation, Inc. ("OPG").

1.2 The OEB's Process to Develop the RPP

1.2.1 RPP Working Group

The Board invited stakeholders to participate in an RPP Working Group to explore the issues and principles for an RPP to replace or amend the SSS Code. The Working Group mandate was to recommend to OEB staff specific elements and principles for consideration by the Board in the RPP.

The Working Group had three representatives each from retailer, local distribution company (LDC) and consumer groups, two customer information/billing systems supplier representatives, and a representative of the Independent Electricity Market Operator (IMO). There were also two observers, one each from the Ministry of Energy and Ontario Power Generation. See Appendix B for a full list of the Working Group members.

The Working Group met seven times over a period of two months. A summary report of the Working Group's deliberations and recommendations was prepared in mid-November 2004. The issues that were discussed and the recommendations of the Working Group were key inputs for this document. However, on several important elements of the RPP, the Working Group was unable to reach a consensus. In these instances, the Working Group report presented a synopsis of the Working Group debate of the issues and, when possible, offered several options for Board staff to consider in making recommendations to the Board.

1.2.2 Board's Proposal

The Board's RPP Proposal synthesizes input from the Working Group into a comprehensive RPP proposal. It is intended to elicit comment and input from interested parties on the Board's proposed methodology and structure for the RPP. The Board encourages interested parties to forward written comments on this Proposal and participate in a half-day workshop on the elements of the Proposal.

1.2.3 Regulatory Instruments for RPP Implementation

Implementation of the RPP will require new regulatory instruments. Once consultations on the Board's Proposal have been completed, the Board will issue proposed regulatory instruments that will, once finalized, give effect to the RPP. In addition to codifying the elements of the RPP, the Board will need to eliminate or amend the Standard Supply Service Code and amend the Retail Settlement Code. Interested parties will be encouraged to comment on the proposed new or amended Codes in accordance with the Board's statutory "notice and comment" procedure for electricity codes. This may include a second round of "notice and comment" if there are any subsequent material changes to the initial new or amended Code provisions. Implementation of the RPP will also require amended rate orders for distributors, and may also require amendments to distribution licenses.

1.2.4 Out-of-Scope Issues and Information Constraints

Bill 100 requires that the first RPP prices set by the Board remain in effect for not less than 12 months. Accordingly, the Board's proposals in this document on matters such as the frequency of price adjustments apply to year two and beyond.

The Government has yet to specify which consumers will be eligible for the RPP. The Board is of the view that, until it is advised otherwise, it should assume the status quo in terms of RPP eligibility. The status quo includes low volume consumers (those that use less than 250,000 kWh of electricity) and designated consumers, which includes municipalities, universities, schools and hospitals. This matter should be clarified in a forthcoming Government regulation. It is important to note that the definition of eligible consumers could have an impact on elements of the RPP such as customer mobility. As and when a regulation is made that clarifies eligibility for the RPP, this will be taken into account by the Board in the Code development process referred to in the preceding section.

The form and content of electricity bills for low-volume consumers is another issue that is outside the scope of the RPP process. It is being dealt with through a separate Government process on the simplified consumer bill. Thus, issues such as whether or not the "Global Adjustment" can or should appear as a separate line item on consumer bills are not addressed in this Proposal, nor will they be reflected in the RPP implementation documents.

The regulated price applicable to OPG's designated regulated facilities, which is a key element of the blended supply price on which the RPP prices will be based, will be established by regulation at a later date. It is not currently within the Board's mandate to set this price, nor is the Board presently in a position to know what that price will be.

The Board requests the public and stakeholders to focus their comments on the elements in Section 2 of this document. Comments on bill content/design, OPG regulated pricing and the definition of customer eligibility are outside the Board's mandate with respect to RPP.

2.0 Elements of the RPP

The RPP is comprised of a number of specific elements, i.e., methodologies and principles that implement the policy intentions and objectives of the RPP. These elements were "decision factors" for the Board, e.g., the Board chose between alternative constructs and formulations of these elements, using precedents, principles and the objectives that guide the Board in formulating a proposal for the RPP that will achieve the Government's stated policy objectives. This section presents the Board's choices for specific elements and constructs for the RPP.

2.1 Activation of Smart Meter RPPs

Early in its deliberations, the Board decided that the RPP should be comprised of separate plans for "conventional" meters and "smart" meters. To optimize the energy cost management, load shifting and conservation potential of the smart meter deployment initiative, the Board advocates a different approach for some specific elements of commodity pricing for eligible consumers that have smart meters.

The penetration of smart meters into the expected RPP eligible customer classes is expected to accelerate in the coming years. Some existing consumers, currently eligible for the existing two-tiered price plan, already have smart meters in place, or meters that can measure consumption on a time-of-use basis. To capitalize on these existing meters, the Board proposes the mandatory application of a smart meter RPP for any eligible consumers that have smart meters in place on or before May 1, 2005 and who elect to remain within the RPP. LDCs shall implement appropriate modifications to billing systems, including manual operations if necessary, to comply with this objective.

One consideration in implementing the smart meter RPP, for eligible consumers, is the cost of customer information and billing system changes to support the full-scale deployment of smart meters. The Board recognizes that these changes may not be cost effective for all LDCs because smart meter deployment may be uneven with respect to LDC service territories. The Board observes that if a smart meter pricing option will be required no later than May 1, 2005 for eligible consumers with smart meters in place, then the extension of this option to other consumers should be relatively straightforward. Recognizing that, under the *Draft Implementation Plan for Smart Meters*, a smart meter requirement for new installations will not begin until some time in 2006, the Board proposes that all LDCs shall have in place by January 1, 2006 the capability to administer a smart meter RPP for eligible consumers. This capability shall include "dynamic enrollment" for eligible consumers, i.e., consumers will be enrolled in the smart meter RPP by the next billing cycle after activation of their smart meter.

Board Proposals - Smart Meter RPP Deployment

- **Mandatory application of a smart meter RPP for any eligible consumers that have smart meters in place as of May 1, 2005 and who elect to remain within the RPP. LDCs shall implement appropriate modifications to billing systems, including manual operations, to comply with this objective.**
- **All LDCs shall have in place by January 1, 2006 the capability to administer a smart meter RPP for eligible small volume consumers. This capability shall include "dynamic enrollment" for eligible consumers, i.e., consumers will be on the smart meter RPP in the next billing cycle after activation of their smart meter.**

2.2 Elements Common to the Conventional & Smart Meter RPP

In formulating its proposal, the Board decided that some common elements apply to both the conventional and smart meter price plans. These elements form the "core" of the replacement and/or amended Code.

2.2.1 Cost Recovery Objective

The policy objectives of the RPP include the expectation that eligible customers will pay the “true cost of electricity”. The Board proposes that the RPP should recover “annual supply costs” on a one-year forward basis for the forecasted RPP supply requirements. Annual supply costs are determined by summing the costs of energy supplied to RPP consumers through the IMO-administered wholesale market. These supply costs are generated by several pricing methods (contract, regulated and market prices) and the associated energy quantity delivered.

The Board proposes a methodology to determine the RPP supply cost that is based on a supply-weighted blending of the costs of the “hybrid” market supply streams. These supply streams are the existing non-utility generator (NUG) contracts, the designated assets of Ontario Power Generation (baseload hydro-electric output and nuclear supply), contract-based new supply, and market pricing for the remaining supply. Information requirements for these supply streams include the prices paid for the contract-based (NUGs and new supply) and designated asset supplies, a forecast of the hourly energy market price and energy quantities from each supply source to match the forecasted RPP load. (See Appendix A for a fuller description of the price blending process).

Forecasted RPP load is a subset of total forecasted Ontario load. RPP supply is defined as a percentage of the total annual forecasted Ontario supply that serves Ontario load. Because supply and demand, or load, must always be equal (there is very limited storage capability) in an electricity network, the RPP supply as a proportion of total supply for Ontario load will be equal to the percentage of total domestic load represented by RPP eligible consumers.

In addition, the Ontario Power Authority (OPA) may incur other costs associated with funding the RPP, such as interest costs for holding a variance account debit balance. These costs should be recovered from RPP customers and included in the RPP supply cost calculation. Other costs associated with the RPP, but not directly related to the commodity costs of electricity, such as LDC administrative and system development and modification costs, will be excluded from the supply cost determination.

The RPP is a forward-looking, prospective price plan based on forecasts of expected demand, supply and market prices. The costs to be recovered by the RPP depend on suppliers meeting their contract obligations for energy deliveries. Each of these forecast inputs and contract obligations are subject to error or non-fulfillment, resulting in the RPP either over-recovering or under-collecting the expected supply costs. These “out of plan” surpluses or shortfalls, will be accumulated in a variance account held by the OPA. The variance account will be cleared, either through additional collections from RPP consumers or credits to RPP customer accounts. (See section 2.2.2 - Price Setting Methodology, section 2.2.3 - Price Adjustment Methodology and section 2.2.5 - Variance

Monitoring.)

Board Proposals - Cost Recovery

- **The RPP will be a one-year plan that recovers the expected "supply costs" of the RPP load for that year.**
- **"Supply costs" include the expected costs of energy from four supply streams – NUG contracts, OPG's designated assets, new supply contracts and market-priced supply – and any direct, supply-related costs incurred by OPA in meeting the RPP supply obligations.**
- **RPP load and supply obligations and market prices will be determined from the Board's forecasts of market demand, supply and price.**
- **Cost recovery shortfalls or overpayments will be accumulated in a variance account administered by the OPA. This variance account will be cleared in accordance with a schedule and protocols set by the Board.**

2.2.2 Price Setting Methodology

The RPP cost recovery objective determines the total amount of revenue to be collected from RPP consumers in a price plan year. The overall objective is to set prices to collect revenues to ensure that the expected value of the OPA's RPP variance account is zero by the end of the RPP year. However, RPP prices need not be a simple "cost divided by supply equals price" equation. The RPP has multiple objectives beyond ensuring that RPP consumers pay the true cost of electricity.

These objectives include supporting conservation and load shifting actions by consumers and complementing smart meter deployment. At the same time, the RPP will have stable and predictable prices to assist consumers in planning their electricity consumption and budgets. In order to support the conservation and load shifting objectives, the RPP price structure will loosely replicate market pricing — when load increases, supply costs increase as more costly generation is added to the supply mix. At the same time, the RPP will be neutral with respect to investor decisions for new supply projects.

In the RPP, the OPA is not required to bid RPP load into the wholesale market as a price sensitive load. Fluctuations in RPP load, and revenue collected, are absorbed in the OPA variance account to be recovered either through a price rebasing or a true-up. (See section 2.2.3 - Price Adjustment Methodology, and section 2.2.5 - Variance Monitoring.) The OPA will not operate like an active retail supplier with a portfolio of negotiated supply contracts that assume the load and price risks.

To support the conservation and load shifting objectives, the RPP will take two different approaches depending on consumers metering capabilities. (See section 2.3 - Conventional Meter RPP and section 2.4 - Smart Meter RPP.)

2.2.3 Price Adjustment Methodology

The RPP is an annual plan. Prices are set on a prospective basis to recover the expected supply costs over the period of the plan. However, unforeseen circumstances could cause either supply or demand to not match forecast levels at any time within the plan period, resulting in supply costs deviating from forecasted levels.

There are two primary components associated with a price adjustment — true-ups and rebasing.

True-ups are a *retrospective* price adjustment mechanism to collect from (or pay to) RPP customers the accumulated RPP variances. These variances arise from the differential between the *actual* and *forecast* RPP supply costs. True-ups adjust the RPP price so that the revenues collected will clear the variance over the next 12 months. The primary issues that need to be addressed are the frequency of adjusting the true-ups, whether the true-up should be automatic or triggered, and whether there should be a cap on the size of the true-up.

Unlike true-ups, rebasing is a *prospective* price adjustment to reflect changes in the expected RPP supply cost going forward. Similar to true-ups, an issue to consider is the frequency of price rebasing, or, how often the RPP price is reset. There is also the issue of how to coordinate the rebasing and true-up processes to minimize the frequency of RPP price changes.

Rebasings and true-ups will be implemented as a single integrated process, i.e., a true-up will not be made without first looking at future expected events. However, the Working Group had several different views about the frequency of price adjustments. Early in the Working Group deliberations, most members supported quarterly adjustments similar to the Ontario natural gas utilities. These members placed a high priority on cost reflectivity. Others supported annual price adjustments, emphasizing price stability and price predictability.

Many Working Group members changed their views on quarterly adjustments because about 75% of LDCs use bi-monthly billing. With bi-monthly billing and quarterly adjustments, RPP consumers would see a price change on almost every bill that they received. This is unacceptable given the objectives of price stability and price predictability.

The Working Group ultimately converged on semi-annual price adjustments with a “trigger”. The trigger, which could be either a specific variance account balance level or a prospective percentage change in RPP prices, ensures that variance account balances do not become excessive and unmanageable. The trigger mechanism was considered to be an appropriate compromise between the competing objectives of price stability and cost reflectivity.

Given the above, the Working Group agreed that there should be a move to quarterly adjustments after all LDCs adopted monthly billing, which should coincide with the accelerated penetration of smart meters in the market.

At the outset of its deliberations, the Working Group decided that fully achieving all of the objectives for the RPP would be difficult because the objectives were by definition competitive and contradictory. For example, price stability and price predictability suggest relatively infrequent true-ups (e.g., annually). At the same time, an RPP price that reflects the true cost and encourages conservation suggests relatively frequent true-ups (e.g., quarterly).

The Board agrees with the Working Group recommendation that the price adjustment should be an integrated process and that the frequency of adjustments should be phased-in and reassessed in successive annual iterations of the RPP. The proposal presents a smooth transition from annual price adjustments in year one, to semi-annual adjustments with a trigger during the transition years and a move to a quarterly approach, similar to the natural gas Quarterly Rate Adjustment Mechanism (QRAM), to coincide with smart meter penetration.

The Board also supports the recommendation that any price adjustment would need to exceed a certain threshold before it was implemented. This is important because the Board prefers to avoid imposing costs on the system to implement a price adjustment that is immaterial. In addition, consumers may consider frequent small price changes to be “nuisance” changes compared to less frequent but larger price changes.

The Board also supports synchronizing RPP price adjustments and distribution rate changes. This avoids exposing consumers to multiple consecutive bill impacts and permits LDCs to make all billing system changes at the same time in order to avoid imposing additional costs.

The Board considers it inappropriate to impose an arbitrary cap on each RPP price adjustment. Such a cap, applied to a single line item on the consumer’s bill, negates one of the primary benefits of synchronizing the RPP price and distribution rate adjustments. The Board believes that it is more appropriate to assess the aggregate impact on consumers of all adjustments before deciding on any individual line item.

Board Proposal – Price Adjustment Methodology

- **Price adjustments — true-ups and rebasing — should be an integrated process.**
- **Price adjustments will only be implemented if the required price change exceeds a minimum threshold. The Board will set the methodology for this determination and the threshold.**
- **After the initial 12 months of the RPP being active, price adjustments will be semi-annual unless the prospective year-end variance account balance exceeds a trigger level.**
- **When the prospective year-end variance account balance does reach a trigger level, between semi-annual adjustments, there will be a true-up to recover the full variance. This true-up will take into account seasonal variations in prices and extraordinary circumstances, such as significant interruptions in supply.**
- **True-up levels should be set to recover the variance over a 12 month period.**
- **The Board will begin to synchronize RPP price adjustments with distribution rate adjustments starting on or before May 1, 2005.**
- **There will not be an explicit cap on the size of each RPP price adjustment.**

2.2.4 Notification of Price Adjustment

Advance notice of price adjustments will be important for LDCs and RPP consumers. RPP consumers will need to be notified of a price change before the new price appears on their bills. LDCs will also need to be notified in order to make the necessary billing system modifications before the price change goes into effect.

The timing of the advance notification is a consideration. For example, if the notification period is too long, the price forecast that will have been used for price adjustments will be less reflective of current cost conditions. At the same time, consumers should be notified of a price change prior to it going into effect so that they can adjust their electricity consumption.

In the Ontario natural gas sector, consumers do not get prior individual notice of price changes. Any individual notice is received after the price change, typically by means of bill inserts included with the first bill that reflects the price adjustment.

The Working Group discussed extensively the lead time that LDCs would need to implement various types of price adjustments and to notify customers. For simple price changes, about 30 days are required before the customer billing date, which is only 15 days before the effective date. For structural changes (e.g., changing tier thresholds), the LDCs need to be informed 90 days before the customer billing date, which is 75 days before the effective date. These time periods are required to enter the new prices into LDC's billing systems and then to test them in dry runs before sending out "live" bills to consumers. The 15 day differential in both cases above reflects a lag of 15 days between LDC meter readings and "live" bills going out to consumers.

Board Proposal – Notification of Price Adjustment

- **LDCs will receive at least 15 days notice prior to the effective date for a simple price adjustment.**
- **For more complex price structure changes requiring Customer Information System modifications, LDCs will receive a maximum of 75 days notice prior to the effective date.**
- **RPP consumers will receive notification of approved RPP price changes 15 days before the effective date through an OEB news release and postings on LDC, OEB, and other websites.**
- **LDCs will be required to provide RPP consumers with a more a formal individual notification of RPP price changes through bill messages and bill inserts, starting as soon as the LDCs are notified of the RPP price change.**

2.2.5 Variance Monitoring

The prospective balance of the OPA's RPP variance account, i.e., the expected end-of-RPP year balance, will be a critical variable for the Board to monitor.

The level of the variance account is expected to cycle throughout the year, reflecting the averaging of supply costs in the RPP prices versus the expected fluctuation of the actual prices as a result of seasonal changes in demand levels. However, unusual events, such as unanticipated supply interruptions, can also cause the variance account balance to deviate from its expected path.

The variance account will be monitored by the Board on a regular basis, most likely monthly because of the monthly settlement cycle for the IMO-administered wholesale market. In establishing the annual supply costs for the RPP, the forecasted monthly market price and the supply schedules of the various contracted suppliers will generate a “shadow variance account”, i.e., a monthly expected balance as smoothed average prices for RPP loads collect revenues to satisfy the expected annual supply cost. At any particular monthly interval, this shadow variance account can be compared with the actual variance account to ascertain if corrective action in the form of a “true-up” or rebasing of the RPP is required. Such corrective actions will need to take into account the expected variations in price, which have been considered in the price forecast. The Board will establish criteria for triggering a mid-RPP year true-up or rebasing that will address unexpected variations and balance the need to keep the variance account within a reasonable year end balance against the instability and nuisance impact of a mid-year RPP price change.

Given the above, there may be times when it appears that corrective action is necessary but the variance balance is, in fact, in line with the price forecast.

Board Proposal – Variance Account Monitoring

- **The Board will monitor the OPA’s RPP variance account balance on a regular basis, most likely monthly.**
- **The RPP supply cost calculation will include a monthly variance account balance forecast for the RPP year, reflecting seasonal variations in peak and off peak supply costs and the cumulative revenues of the RPP’s smoothed average prices.**
- **The Board will establish criteria (absolute dollar amounts or a percentage of total RPP supply costs) to determine if the RPP variance account balance requires a mid-year RPP true-up to ensure that the end of year balance will be within a reasonable range. The Board will balance the need for stability and predictability in the RPP prices against cost-reflectivity and fiscal responsibility in making this determination.**

2.2.6 RPP Consumer Mobility

In other jurisdictions that have restructured their electricity markets and offer retail choice, the consumer mobility debate often focuses on whether “exit fees” should be charged to consumers when they leave default supply. These "exit fees" are an incremental charge beyond what the customer owes, based on their consumption, up to the date that they switch to a retailer. Most jurisdictions do not have exit fees primarily because they are seen as a barrier to retail choice. Only a few jurisdictions, such as Maine, have exit fees.

The Working Group discussed requiring LDCs and RPP consumers to settle the amount that they owe, or, are owed, in the variance account when a consumer moves or switches to a retailer. The primary reason for not having such a settlement is that it would require LDCs to track each individual RPP consumer account to determine the precise amount involved. LDC members of the Working Group thought that significant computer information system (CIS) investments would be needed to deal with amounts that might be relatively immaterial.

The Working Group concluded that RPP consumers that move to a new location either within or out of the province are not a significant concern. Those that leave the province are only 2 to 3 per cent of total consumers. Those that stay in the Province and remain on RPP will pay or receive approximately what they owe, or, are owed, at their new LDC when the price is adjusted or re-based. Therefore, requiring a settlement for consumers that move would probably result in those consumers paying or receiving the variance settlement twice unless an offsetting account entry was made in the new account. The Board agrees with the Working Group's recommendation, and is not proposing any form of variance settlement for consumers that move to a new location and stay on the RPP.

The more difficult issue is whether a variance settlement should be required of a consumer that leaves the RPP in favour of a retail contract or supply based on the spot market price pass through.

A guiding principle for the Board is to strive to remain "neutral" in terms of retail choice, i.e., providing neither an incentive nor a disincentive to RPP consumers to choose retail supply contracts. This principle suggests that there be no incremental "exit fees" but RPP consumers should be required to settle with the LDC any amount attributable to them in the OPA's variance account. Not requiring such a settlement would result in the Board facilitating or impeding retail switching.

Board staff advised the Working Group that the Board would be unable to justify this type of *de facto* cross-subsidization based solely on "qualitative" claims of significant CIS costs. Further information in the form of real "quantitative" cost estimates would be required for the Board to even consider this option. LDC Working Group members, with their CIS/IT vendors, are in the process of estimating these costs.

If LDCs ultimately demonstrate that it would be costly for them to determine the precise amount of the settlement, the most appropriate route would likely be a method to estimate the variance attributable to each RPP consumer. This would minimize cross-subsidization and avoid new CIS investments, which would ultimately be passed on to consumers. One relatively simple and straight-forward option would be to use the specific consumer's most recent consumption level which LDCs would have in their billing systems and multiply that by a "per unit variance account recovery factor" that should be readily available, or computable from data held by the OPA.

The Board proposes that consumers who leave the RPP, for a retail supply contract or the spot price pass through option, pay or receive a settlement through an approximate payment. This payment will be calculated by multiplying the consumer's accumulated consumption since the beginning of the most recent RPP price setting period by a per unit charge that represents the most recent monthly status of the OPA's RPP variance account for the current RPP price year. In addition, consumers will be charged or credited any remaining variance account true-up from the previous 12-month period based on an estimate of their annual consumption *minus* consumption to their exit date *multiplied by* the per unit variance account balance as determined at the last RPP price setting.

The Board will determine per unit settlement factors. In the case of debit balances, LDCs will supply the relevant consumption data, issue final bills to exiting consumers on a net basis, i.e., balancing variance account debits and credits, and remit collections to the IESO who will forward remittances to the OPA. In the case of a net consumer credit balance in the consumer's variance account, the LDCs will credit consumers on their final bill, issue a debit invoice to the IESO who will collect from the OPA and credit the LDC's account.

Board Proposal – Consumer Mobility

- **Only consumers who leave the RPP and elect to receive supply, via a retail supply contract or spot price pass through, will be subject to a "variance account final settlement" charge or credit.**
- **The Board will determine a monthly "RPP variance account settlement factor" for the current RPP year based on the most recent monthly OPA RPP variance account cumulative balance divided by total RPP supply for the same period. This factor will be multiplied by a consumer's cumulative annual consumption in the current RPP year to obtain a debit/credit to be paid/received by the consumer on exit.**
- **Any variance account balance from the previous RPP price year will also be settled based on estimated remaining annual consumption multiplied by the settlement unit amount for the previous year.**
- **LDCs, the IESO and OPA will establish accounting systems and protocols to ensure the appropriate financial flows to/from consumers.**

2.3 Conventional Meter RPP Pricing

The Working Group debated whether the tiered pricing structure should be retained or eliminated going forward. Opinions in the Working Group were varied. Some Working Group members suggested that there is no evidence the introduction of tiered pricing has encouraged conservation efforts. Others thought that the tiers were effective as an incentive for conservation and supported the “conservation culture” envisioned by the Minister, but could be improved upon. Almost all agreed that there was not enough experience and data to be able to determine the effectiveness of tiers at this time.

The Board considers it premature to judge the effect tiers have had given that most consumers have received only a few bills since tiers were first introduced and behavioural change takes time. In addition, to reconsider each substantive price “structure” change, such as now going back to a single price for all consumers, after only 8 months of tiered pricing, could set a precedent that is neither prudent, stable or predictable.

The Board therefore proposes that tiered pricing should be retained as part of the conventional meter RPP. The proposed RPP for consumers with conventional meters builds on the existing tiered structure, with different prices for different levels of consumption. Consumers will pay higher fixed prices for electricity as their consumption increases. The tiers will be set so that consumers will have a realistic opportunity to reduce their energy bills by adopting simple but effective conservation activities.

Under the current two-tiered price system, all eligible consumers are charged on the basis of the same tier structure. The Working Group considered whether non-residential consumers should have a different tier structure because the average price paid for their total consumption was considerably higher than the average price paid by residential consumers. Some Working Group members called this a “cross subsidy” from non-residential consumers to residential consumers. Other Working Group members maintained that non-residential consumers should pay a higher average price than residential consumers because they do have higher total loads and often use more power during peak demand periods when the cost of supplying electricity is higher. It was also noted that adjusting the tiers for only one class — non-residential — would result in a lower average price per kWh for non-residential consumers relative to residential consumers with similar levels of consumption.

Some Working Group members suggested that the appropriate solution to this dilemma was to set the relative tiers for the two consumer classes at the same percentage of total load. For example, the first tier for both classes might represent 60% of the average total load for both non-residential and residential consumers and the second tier the remaining 40%. More tiers could easily be added by changing these proportions. However, to adopt this type of tier allocation, detailed load data by RPP eligible consumer classes is required. It is uncertain whether sufficient data has been collected to support this alternative.

The Board does not doubt that there may be some degree of cross subsidization inherent in any simple two-tiered pricing structure that is applied to all eligible consumers. Whether such cross subsidization is significant is not at all clear. The fact that different consumer groups pay different average prices is not necessarily indicative that there are serious inequities. Quantifying cross subsidization is not a simple task. It requires detailed analyses of load profile information for numerous types of consumers, which has not been undertaken.

If there were compelling evidence that the current two-tier system results in significant cross subsidization among different types of consumers, alternative designs could be considered. For example, if there is evidence that large consumers (such as those with a peak demand over 50 kW) are significantly subsidizing other consumers, consideration could be given to moving to a price plan for those consumers that features a fixed price that is closer to the average price paid by other consumers. It should be noted, however, that if the Board's proposed smart meter RPP is adopted (see section 2.4 – Smart Meter RRP Pricing), some of the largest designated consumers (such as some universities, schools, hospitals, and larger businesses) who already have interval meters would not be eligible for the two-tiered conventional meter RPP anyway. The smart meter RRP would apply to them immediately. Assuming the timetable in the *Board's Draft Implementation Plan for Smart Meters* is accepted, other large consumers will be receiving smart meters in the next two years. Therefore, any special RPP prices for large consumers with conventional meters would likely have a limited life.

2.3.1 Seasonal Tiers

Data supplied by an LDC member of the Working Group, showed that over 60% of the monthly consumption of residential consumers with electric space heating is in the high price tier. By comparison, about 25% of the monthly consumption of residential consumers with non-electric (e.g., natural gas) space heating is in the high price tier.

Given this data, the Board decided that an option worth considering is raising the 750 kWh tier threshold (the lower priced tier) in the winter months and lowering the 750 kWh tier threshold in the summer for residential RPP consumers only. This option could be designed to be revenue neutral. The primary rationale for this option is that a necessity in Ontario's climate, space heating, would be less costly while discretionary uses, such as air-conditioning and pool heaters, would be relatively more expensive.

This modification of the tier levels also supports conservation efforts because consumers are unlikely to turn off the heat on cold winter nights to save money by remaining below the higher priced tier threshold. They are more likely to turn off air conditioning on a hot summer day to reduce costs.

In deciding that seasonal tiers require serious consideration, the Board also took into account a number of other factors. Many consumers that use electric space heating do not have the option of switching to natural gas heating because the infrastructure to supply natural gas is currently restricted to certain parts of the province. The climate in Ontario results in a greater need for heating in the winter months than cooling in the summer months. It also gets dark much earlier in the winter, requiring additional lighting than is the case in summer. All of these factors are compounded in northern Ontario.

Another consideration is that a disproportionate share of residential consumers with electric space heating have low incomes. Statistics Canada data, supplied by the Low Income Energy Network (LIEN) as part of the initial September 10th consultation on the RPP, supports the data used by the Working Group. This data shows that almost 25 per cent of low income consumers have electric heating compared to just over a 12 per cent share for all residential consumers.

The Board is therefore seeking input on two possible conventional meter RPPs: one without a seasonal tier adjustment and one with a seasonal tier adjustment.

Board Proposal – Conventional Meter RPP (Option 1)

- **RPP prices should be set to collect sufficient revenue to ensure that the expected year-end value of the OPA's RPP variance account is zero.**
- **Maintain the *status quo* of a two-tier structure with existing thresholds.**
- **RPP prices for the separate tiers will be set with a differential that will achieve the total revenue objectives for the RPP using reasonable estimates of average load by customer class and elasticities for demand response. The prices for the upper tiers will be higher than the prices for lower tiers.**

Board Proposal – Conventional Meter RPP (Option 2)

- **RPP prices should be set to collect sufficient revenue to ensure that the expected year-end value of the OPA's RPP variance account is zero.**
- **Residential RPP customers will have a two-tier price plan under which the lower tier load threshold will be higher in the winter to accommodate increased demand for space heating load. The lower tier load threshold will be reduced in the summer to achieve revenue neutrality, and encourage conservation and reduce discretionary usage such as air conditioners and the operation of pool equipment.**
- **Non-residential RPP consumers will remain with the *status quo* of a two tier structure with the existing thresholds.**
- **RPP prices for each tier will be set with a differential that will achieve the total revenue objectives for the RPP plan using reasonable estimates of average load by customer class and elasticities for demand response. The prices for upper tiers will be higher than the prices for the lower tiers.**

2.4 Smart Meter RPP Pricing

Smart meter technology will allow the use of time-of-use (TOU) pricing to encourage load shifting and conservation activity by consumers.

The Working Group explored various combinations of price levels and seasonality for RPP prices to complement smart metering. These included price data to support a daily TOU pricing scheme with three daily price intervals: off-peak, mid-peak, and peak. The Working Group did not suggest a ratio based relationship among the prices but noted that, in other jurisdictions, a 1:2x:3x ratio was employed where the peak price was three times the off-peak price.

The Working Group supported a seasonal differentiation of the peak periods. Summer peak hours were defined as working weekdays from early afternoon to early evening; winter peak hours were somewhat later in the day, reflecting increased heating and lighting load in winter. As with the RPP for consumers with conventional meters, the Board will consider seasonality in the RPP for consumers with smart meters to assist consumers with electric space heating.

The Working Group suggested three seasons for the TOU price plan: winter – December through March; summer – June through September; and, shoulder seasons of April through May and October through November.

The Board examined the historic seasonal differences in the Hourly Ontario Energy Price (HOEP) since May 2002, which was supplied by the IMO (see chart in Appendix C). The data showed that electricity prices in the shoulder seasons (Autumn and Spring) were quite similar to the prices in the Summer and Winter seasons. The reason behind this lack of seasonal pricing differentiation is that, while consumer demand tends to decline in the shoulder seasons, Spring and Autumn are also “repair seasons” for generators. As a result, scheduled outages during these periods reduce electricity supply.

The Board is, accordingly, of the view that introducing shoulder seasons into the pricing plan was unnecessary at this time. The Board also considered that it would be easier for RPP consumers to understand, particularly during the initial RPP transition, if there were only two seasons with the same three pricing levels, as opposed to shoulder seasons with two price levels and the Summer and Winter with three pricing levels. Seasonal differences in total cost of supply to RPP customers resulting from such things as changing volumes and daylight hours can be accommodated by changing the intervals during each day over which each of the three pricing levels is applied. The Board will continue to monitor seasonal pricing, going forward, to determine if the introduction of shoulder seasons may be justified at a later date.

Board Proposal – Smart Meter RPP

- **Time of use (TOU) prices must reflect forecasted supply costs to meet peak, off-peak and middle load levels.**
- **The TOU price structure should have three daily price levels – off-peak, mid-peak and peak. The appropriate relationship between these prices will be governed by the need to recover forecasted supply costs. The Board will set this differential based on the actual costs of supply for each of contracted supply and OPG’s designated asset supply plus the forecast of market prices for the residual supply to satisfy RPP load.**
- **There will be two seasons – summer (May to October) and winter (November to April).**
- **Peak and off-peak hours in the winter and summer should differ to reflect the different seasonal load shapes.**
- **Consumers with smart meters will have the same supply choices as conventional meter consumers (RPP, retail contract or spot market pass-through) but will not be allowed to use the conventional meter RPP.**

2.4.1 Critical Peak Pricing

Critical peak pricing is a form of pricing that is triggered by particularly tight supply and correspondingly high market prices. An example of a critical peak pricing triggering event would be a very hot day when the IESO relies heavily on imports to meet increasing consumer demand. As such, critical peak pricing would go into effect only on a limited number of days each year.

Under a critical peak pricing scheme, which would only apply as part of the smart meter RPP, the critical peak pricing event would be announced a day ahead and would likely only be in effect for a few hours the next day. In other jurisdictions that have adopted or are testing critical peak pricing, the price tends to be about six or seven times higher than the average electricity price in other hours. For example, if the average price is about 6 cents per kWh, the price during "critical" peak periods would be about 40 cents per kWh.

The Board is of the view that critical peak pricing could be a valuable tool to send a strong financial signal to consumers that they need to cut back on their energy consumption when the system is expected to be at its limits. At the same time, the Board considers it imprudent to implement critical peak pricing immediately in May 2005 for several reasons:

- To date, critical peak pricing has been implemented in only a limited number of jurisdictions and only on a *niche or pilot* project basis. In those cases, it has also been implemented on a *voluntary* basis only. There has been no experience to date with the mandatory application of critical peak pricing across all consumers or even across an entire customer class.

- A move to three daily price levels, which vary by season, will likely be a significant adjustment for the majority of consumers, particularly residential consumers. Adding critical peak pricing into the mix immediately may simply be too complex for most consumers to understand and respond to during the initial transition. It is important to keep in mind that tiered pricing is the most complicated form of electricity pricing that most consumers have been exposed to so far.

- There will only be a handful of RPP-eligible consumers with smart meters installed at the outset and a smart meter is necessary for reacting to critical peak pricing.

Given the above, the Board proposes to postpone implementation of critical peak pricing until smart meters have penetrated the Ontario electricity market and RPP consumers have begun to become accustomed to time of use pricing. When the IESO does make a special request for consumers to cut back on their consumption, there is little response from the types of consumers who will be eligible for RPP. This is likely due in part to the fact that there are no direct financial consequences of continuing to use power at the same level. Critical peak pricing would put in place those financial consequences.

The Board does propose to undertake further research beginning immediately after the RPP is implemented. If the research supports the mandatory implementation of critical peak pricing, it could follow in the near future. This research may include voluntary pilot programs that will assist in: determining the optimal critical peak pricing structure, identifying appropriate communications strategies, assessing the need for any required infrastructure beyond smart meters (e.g., load control devices) and the likely impact on RPP consumers.

Until critical peak pricing is implemented, the Board may also consider issuing a communiqué following each event that could be a critical peak pricing trigger. Such a communiqué would include the price consumers would have paid under a critical peak pricing regime, the number of hours that critical peak pricing would have been in effect and an estimate of how much the average customer in each class would have paid over the duration of the critical peak pricing period in the absence of any conservation activity. The communiqué could also describe the estimated reduction in the market price if consumers had responded with a (say 10%) reduction in consumption during the critical peak pricing period. This would educate consumers about critical peak pricing, the financial consequences of not responding through conservation and the benefits to all if consumers did conserve.

Board Proposal – Critical Peak Pricing

- **Review province-wide implementation of critical peak pricing once smart meters have begun to penetrate the Ontario electricity market. Publish a plan for critical peak pricing implementation by May 2006.**

- **In the mean time, undertake further research into critical peak pricing beginning immediately after RPP is implemented in May 2005. Such research may include voluntary pilot programs.**

- **Until critical peak pricing is implemented, the Board may issue communiqués designed to educate consumers about critical peak pricing events, the potential financial consequences of not cutting back during a critical peak pricing period and the benefits to all consumers, in the form of lower average market prices, if they conserve.**

3.0 Next Steps

This document is being released for review and comment on the Board's initial proposal for the RPP.

The Board encourages all interested parties to file written comments on the proposed RPP.

The Board will hold a half-day information session and workshop on the RPP proposals in this document on the afternoon of December 14, 2004 in the Board offices at 2300 Yonge Street, 25th Floor, Toronto. Interested parties are urged to register for this session.

For details regarding the process for providing written comments on this document, please refer to the accompanying letter. This letter also discusses the Workshop and the process for registering.

While the Board understands that interested parties may have views on the out-of-scope issues identified in section 1.2.4, interested parties are urged to restrict their comments to the elements of the RPP as described in section 2 of this document.

APPENDIX A

Methodology for RPP Price Blending

The “blended” price for the Regulated Pricing Plan (RPP) will be comprised of a number of different prices from different streams of generation, as per the left side of the diagram below (see Figure 1). There will be a price for OPG regulated assets that will change infrequently. Similarly, there will also be a relatively constant price associated the existing non-utility generation (NUG) contracts. Going forward, costs associated with the two RFPs recently issued by the Government will also need to be recovered (i.e., 2500 MW of supply/DSM and 300 MW of renewable generation). The blended price will also include “market prices” or the Hourly Ontario Energy Price (HOEP), which is determined in the IMO-administered markets.

OPG's nuclear and major baseload hydroelectric generating units (Saunders, Beck, and DeCew Falls) have been designated as “regulated” assets with the price for supply from these plants to be set initially on a cost-of-service basis via regulation by the Government. The Board will not know this price until the Government issues a regulation. In the future, the price for the output of these plants will be established by the OEB.

The NUG contracts are long-term contracts that were initially entered into by Ontario Hydro. There are a number of contracts with varying prices, terms and conditions. The information will not be available to the Board for each specific contract. The Ontario Financing Authority (OFA) has committed to provide the necessary pricing and quantity (MW) information to the Board in late 2004.

The costs associated with the OPG regulated assets and the NUG contracts represent what will be referred to as the Global Adjustment, which is labeled in green in Figure 1.

It is expected that none of the new generation resulting from the two RFPs discussed above will be operational on May 1, 2005. However, when these contracts are finalized with the OPA and these plants do begin to come on stream, the costs will need to be recovered from all consumers including those consumers on RPP.

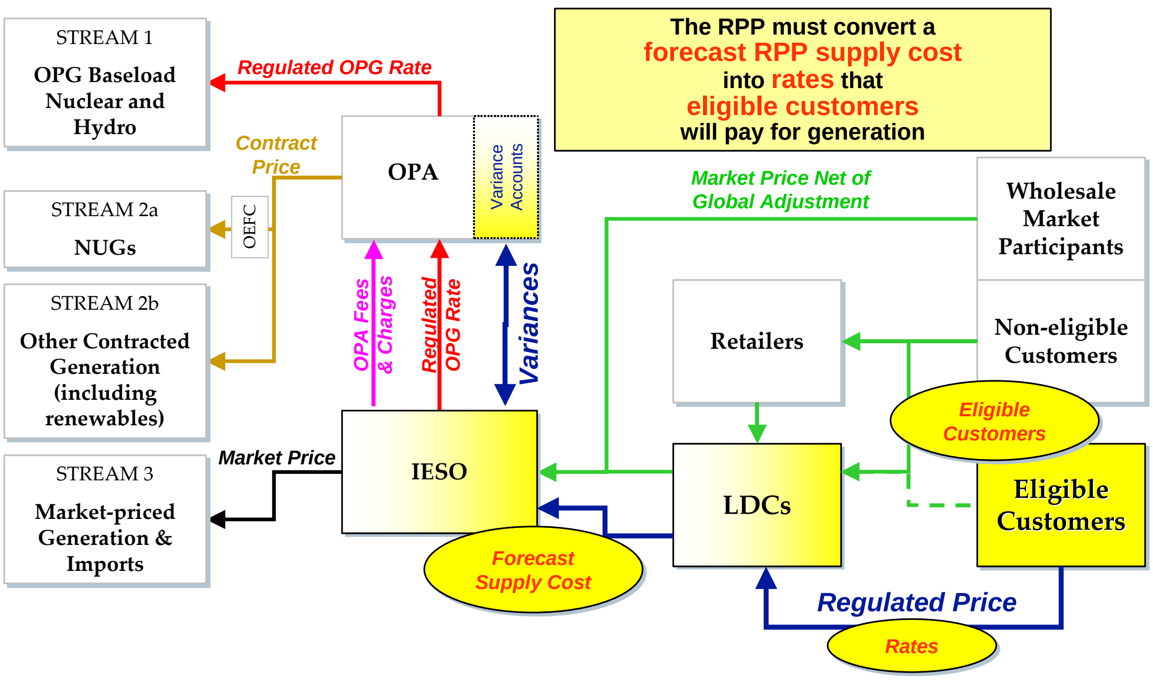
The IMO-Administered market price (for market-priced generation and imports) is set by the IMO through a “stacked” pricing methodology, which matches hourly demand to supply and establishes a market clearing price. Imports do not set the market clearing price.

Since price is a function of supply and demand, the total RPP supply cost to meet RPP consumer demand will be comprised of varying portions of all the above costs from the three primary streams of generation. The proportions will vary to the degree that “regulated” OPG and contracted suppliers, such as the

NUGs, vary their actual supply from their expected output and consumer demand varies from forecast. The IMO-Administered market will provide the balance of electricity supply needed to meet market demand. In other words, it will essentially operate as a balancing market. Accordingly, the total RPP supply cost from these three streams will be converted to a "blended" price that will fluctuate with changes in RPP supply and consumer demand.

The flow of payments associated with the RPP is illustrated by the dark blue line between "eligible customers" and the "LDCs" in the bottom right hand corner of Figure 1 (i.e., Regulated Price). The flow of consumer payments for power consumed is from right to left as the arrows illustrate, while the generated electricity commodity itself is flowing in the opposite direction from left to right.

Figure 1: *RPP in context of the entire electricity market (Source: Navigant Consulting).*



Proposed legislation (Bill 100) requires that the RPP price remain fixed for the first full year, which means that the "blended" RPP price will need to be based on a forecast. As a result, there will be a variance between the "forecast" RPP costs and what RPP customers have paid (i.e., "actual" RPP costs). The variance account will be held by the Ontario Power Authority (OPA) as shown in Figure 1. This RPP variance account will need to be trued up at certain intervals to ensure that the RPP price reflects the "true cost" of the electricity that RPP customers use over time. Given that it is intended that the Global Adjustment will be rolled into the RPP price, a forecast with a subsequent true-up will also apply to these supply costs for RPP customers.

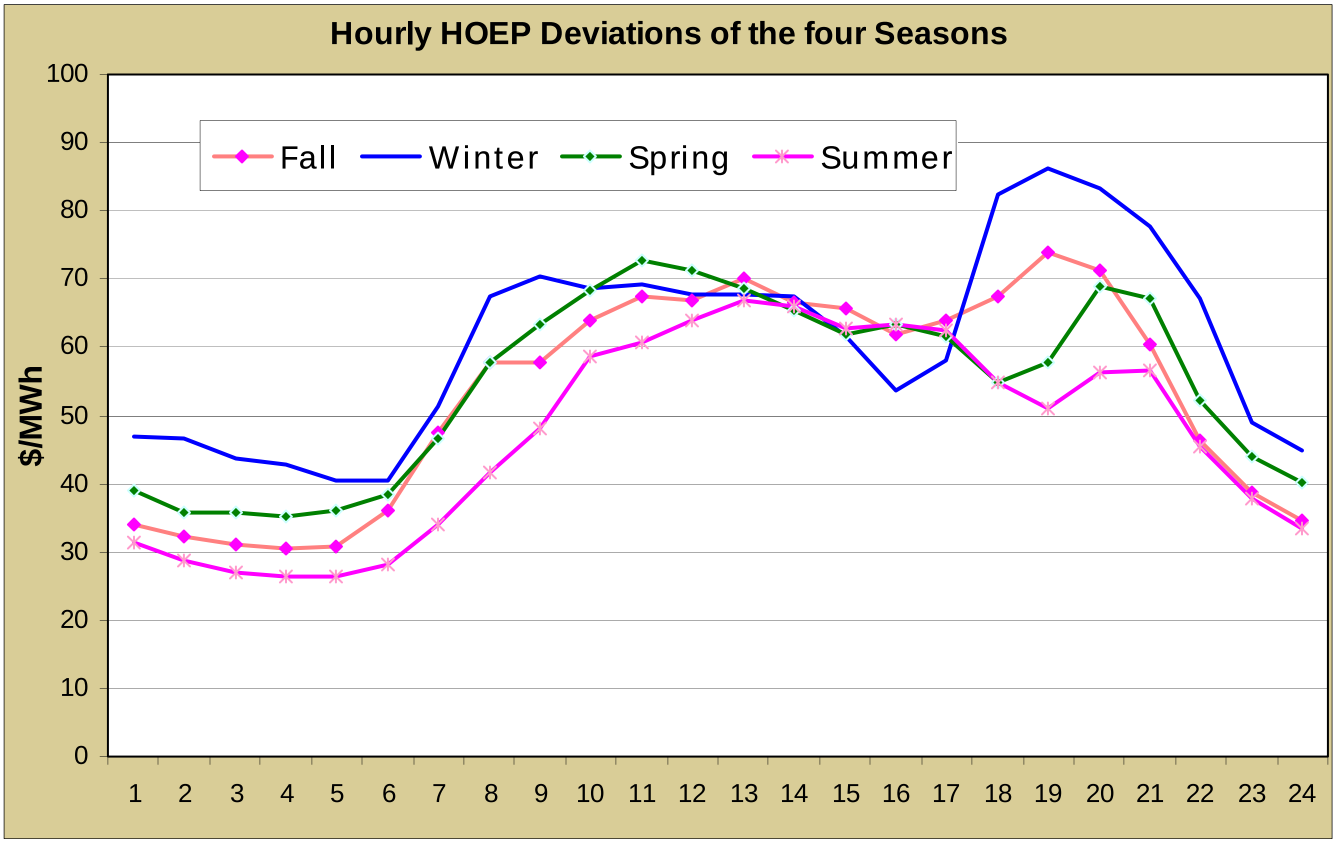
APPENDIX B

Regulated Price Plan (RPP) Working Group	
Members	
Barrie Hydro	John Olthuis
BOMA, FRPO, CIPPREC[1]	Mike McGee
Consumers Council of Canada	Julie Girvan
Cdn. Federation of Independent Business	Bruce Fraser
Coalition of Large LDCs[2]	Paula Conboy
Direct Energy	Ian Mondrow
Electricity Distributors Association	Wayne Taggart
EPCOR Utilities Inc	Leigh-Anne Palter
Independent Electricity Market Operator	Helen Lainis / Joseph Freire
Kinetiq	Jim Steele
Ontario Energy Savings Corp.	Gord Potter
Ontario Federation of Agriculture	Ted Cowan
The SPi Group Inc.	Mark Kerbel
Vulnerable Energy Consumers Coalition	Bill Harper
Observers	
Ministry of Energy	Richard Rogacki
Ontario Power Generation	Barbara Reuber

[1] Building Owners & Managers Association (BOMA), Federation of Rental-housing Providers of Ontario (FRPO), Canadian Institute of Public & Private Real Estate Companies (CIPPREC).

[2] Toronto Hydro, Hamilton Hydro, PowerStream, Veridean Connections, Enersource, Hydro Ottawa, Hydro One.

APPENDIX C



Source: Independent Electricity Market Operator (IMO).