Regulated Pricing Plan Working Group

MEETING NOTES - Meeting #5

Ontario Energy Board
2300 Yonge Street, North Hearing Room

Thursday, October 28, 2004
9:00 a.m. - 4:45 p.m.

Barrie Hydro (John Olthuis)
BOMA, FRPO, CIPREC (Mike McGee)[1]
Consumers Council of Canada (Julie Girvan)
Cdn. Federation of Ind. Business (Bruce Fraser)
Coalition of Large LDCs (Paula Conboy)
Direct Energy (Ian Mondrow)
Electricity Distributors Association (W. Taggart)
EPCOR Utilities Inc (Leigh-Anne Palter)
IMO - Regulatory (Helen Lainis)
IMO - Settlements (Joseph Freire)
Kinetiq (Jim Steele)
Ontario Energy Savings Corp. (Gord Potter)
Ontario Federation of Agriculture (Ted Cowan)
The SPi Group Inc. (Mark Kerbel)
The SPi Group Inc. (Gay Cook)
Vulnerable Energy Consumers Coalition (B. Harper)
Ministry of Energy (Observer - Richard Rogacki)
Navigant Consulting (Mitch Rothman)
Navigant Consulting (Todd Williams)
Ontario Energy Board (Chris Cincar)
Ontario Energy Board (Russell Chute)

NOTES OF MEETING

At the latter end of the previous WG meeting, some of the WG members voiced their frustration. They wondered whether they were wasting their time since so many decisions had already been determined through legislation and regulations. Board staff and Navigant attempted to reassure the WG members that their continuing participation and input was valued and vital to the process since many of the constraints were short-term in nature (primarily in year 1) and their input was needed to develop a plan for the longer-term. In addition, it was noted that the WG member "technical" expertise was of significant value to Board staff and Navigant because they were raising issues and technical limitations that the Board will need to know (and Board staff and Navigant would not have thought of in the absence of this WG process). Moreover, the Ministry would likely not be serving as an observer in this process if they felt they could learn nothing from the broad stakeholder input.

Board staff also distributed copies of a September 11th letter from the Minister of Energy which appeared in the Toronto Star. The letter was in response to an article about the impacts of higher electricity costs on low income consumers. Board staff indicated that this letter was the basis for their position in the WG's third meeting that the specific question of the affordability of electricity can and will be dealt with through other means (i.e., Emergency Energy Fund). Therefore, affordability is not part of the scope for the RPP development, apart from broader considerations such as consumer acceptance, predictability and price stability.

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

Building a New Strawman for Conventional Meters

> Note: The draft WG strawman for conventional meters is included in the attachment to these meeting notes. It is important to note that this represents a preliminary WG strawman, as the WG decided to first focus on the basic concepts, but not necessarily the specific wording, to facilitate the process. In addition, some issues require further discussion. The following is a summary of the discussion around how the strawman was arrived at.

Price Adjustment

The WG then continued where they left off the previous day discussing *Rebasing & True-ups.* The WG concluded that these two elements needed to be part of a single integrated "Price Adjustment" process to *link* the *retrospective* review and *prospective* outlook in order to send the right price signal.

A potential "trigger" for rebasing/true-ups was discussed which would be based on a $ amount per residential customer. The purpose of the trigger would be to prevent buildup of an excessive variance; a true up would be "triggered" if the variance (or a criterion related to it) exceeds a certain level. It was suggested that, with predetermined dates established for automatic or scheduled rebasing/true-ups, some discretion would be necessary. For example, do not act on the trigger if the scheduled rebasing/true-up is only a short time (e.g., 1 month) away in order to avoid multiple true-ups within a very short period of time.

It was also noted that the trigger review (i.e., need to implement) should not be carried out on a quarterly basis in isolation of potential future developments. It also needed to look prospectively to see if that trigger would still be exceeded when the outlook over the next 12 months was also taken into account. Again, this should assist in avoiding unnecessary true-ups that would only serve to whipsaw consumers. *[Note: While the majority supported the above three paragraphs, there was not complete consensus].*

It was also suggested that a minimum price change (or threshold) is needed to avoid price adjustments so small they are in effect a "nuisance".

The frequency of the true-up/rebasing was the sole aspect of the Price Adjustment that the WG was unable to reach consensus on. Three options are proposed: quarterly (with no trigger) vs annually (with a trigger), and, as a potential compromise between these, semi-annual (with no trigger).

Another option, true-ups based on two consecutive quarters of variance account balances, was also discussed but was not seen as a viable alternative.

The rationale put forward for "quarterly" adjustments is that it would be more cost-reflective and consistent with natural gas. Accordingly, it would be easier for consumers to understand, since they would experience the same treatment as they have with their gas utility, and it would be easier to educate consumers. In addition, going forward, gas and electricity prices will be linked to an even greater degree.

Those WG members advocating an “annual” price adjustment noted that it would provide greater price stability and predictability. The rationale put forward for including a “trigger” in this option was to ensure that the RPP variance balance did not become excessive and therefore to avoid price shock.

It was further suggested that one option for the Price Adjustment frequency may be to transition from every 12 months in year 1, then semi-annually in year 2 and, subsequently, move to a quarterly basis once smart meters penetrate the market.

A WG member noted that the OEB will need to order the OPA to report on the variance balance on a set schedule as a condition of the OPA’s license.

It was clarified that references to “threshold” in the presentation referred to the floor or the amount that must be exceeded for the automatic or scheduled (e.g., quarterly, annual) price adjustment to be implemented and the “trigger” was the $ amount that must be exceeded to implement a price adjustment between those scheduled price adjustments.

Seasonality

The WG briefly discussed whether prices should differ based on the season. It was decided against. The rationale is discussed in the attachment.

Notice

A WG member reminded the working group that no prior notice of a rate adjustment was currently provided by Ontario gas utilities. Another WG member suggested that it was not as important in electricity (as gas) to have the forecast as close as possible to the price adjustment, since much more of the electricity market will be hedged (e.g., regulated OPG baseload, NUG contracts). In contrast, much of system gas is based on contracts which are linked to spot market indices.

A WG member noted that there was a need to distinguish between notice for a change in the: (1) price *level*; and (2) price *structure*. The “notice” being decided on here is associated with changes to the “price level”. A change in the price “structure” would require more notice for the LDCs to implement. For example, LDC WG members suggested this would likely require about 90 days, as would any change to the bill print, while a change in the price “level” would likely require 30 days.

The above was further qualified that these time periods could effectively be reduced by 15 days because of 15 day buffer due to a lag between billing and meter reading (i.e., LDCs would need 30 days from initial announcement to bill presentment to consumers). In other words, the LDC could be informed of the price change 15 days prior to the price change going into effect and the LDC would still effectively have 30 days to make the necessary price table changes and to test their systems prior to the price affecting live bill calculations. Similarly, changes requiring programming or extensive tier modifications would require a minimum of 90 days or 75 days including the 15 day lag. It was subsequently suggested that, if no prior notice was provided to consumers, it would still effectively provide the LDCs with the 15 day IMO lag time to adjust their systems. ***[Action: Large LDC Coalition to e-mail concerns to the WG following the meeting with qualifications associated with the time periods above].***

Exit/Entry

The terms under which RPP consumers exited from the RPP was discussed. Navigant identified a number of options including: (1) requiring RPP consumers to pay a true-up when they "moved" or "switched to a retailer" based on the amount in the variance account associated with that customer; (2) not requiring a true-up under either of these circumstances; and (3) only requiring a true-up when a customer switched to a retailer (i.e., not a customer "move").

A rationale put forward by one WG member for not requiring a true-up in either case (move or switch) was that requiring customers to pay would necessitate LDC systems changes to enable them to track the variance on a customer-specific basis and the true-up amounts would not be material enough to justify such CIS investments by all LDCs.

A concern was raised that this option would not result in all RPP consumers being required to pay what they owe (i.e., user pays). As a result, this would result in cross-subsidization since the remaining RPP consumers would be required to pay for variances for energy used by consumers that switched. It was also noted that not requiring a true-up would be inconsistent with the current practice of Enbridge Gas in Ontario.

A further issue raised is that requiring a RPP consumer to pay such a true-up when they "moved" to another LDC territory was that they would likely pay twice — once to the previous LDC upon leaving and again to the new LDC within the normal true-up process. As a result, it was suggested that, if such true-ups were to be required, it should only occur when a RPP consumer "switched" to retailer — not when they "move".

The majority of WG members supported no true-ups on either a "switch" or a "move", primarily due to the LDC CIS investments that would be required for tracking purposes. While there was not complete consensus on this option, neither of the other approaches was advocated as an option for consideration during the meeting.

Tiered Pricing

An LDC WG member noted that tiers were treated differently in the systems of different LDCs. Some LDCs prorated the tiers while others did not. It was mentioned that this could easily be rectified in the code by either requiring all LDCs to prorate or not to prorate (i.e., not leave to individual LDC discretion) to ensure consistent treatment. At the same time, LDC CIS systems differ and therefore requiring all LDCs to prorate could be problematic in terms of implementation.

In response to a WG member suggestion that there was no evidence that the current tiers had accomplished anything with respect to conservation, Board staff noted that the WG should also consider the following: (1) There is also no evidence that it is not accomplishing anything in terms of encouraging conservation; (2) It has only been about 6 months since tiered pricing was introduced and it would likely be prudent to give it a longer period of time than that to see if it is having the desired effect on consumer behaviour; (3) There is a conservation objective and, since seasonal pricing has been decided against by the WG, tiered pricing is the only remaining pricing mechanism available for conventional meters to provide a conservation incentive; (4) As a result, removing tiered pricing (and not implementing seasonal pricing) may be perceived as the WG recommending a step backwards in terms of encouraging conservation.

It was further added by one WG member that there was some evidence that tiered pricing was having the desired effect, in terms of conservation, with respect to water consumption.

A WG member suggested that the current tiers were problematic because they had been developed based on residential usage and since many small businesses consume much more energy, small businesses were consuming more at the upper tier and, in their view, had therefore been subsidizing residential consumers.

The WG then discussed and listed the pros and cons of tiered pricing which can be found in the attached preliminary strawman.

The discussion regarding tiered pricing concluded without a final WG decision. Instead, it was requested that Navigant undertake some further analysis to be presented to the WG at the next meeting so that a more informed recommendation could be made regarding whether the tiers should be differentiated for the residential and small business customer classes. ***[Action: Navigant to undertake the above noted analysis and present the results at the next WG meeting].***

Other Issue

An issue was raised by a WG member which was not directly related to any of the elements in the strawman that were previously identified by Navigant. It was suggested that there was a need to reflect the LDC costs of providing default supply in the RPP price. Another WG member noted that such costs are already currently reflected in a separate line item referred to as the SSS Administration Charge on the consumer's bill and that, under the "standardized" bill, this charge (which is applied to only default supply or standard supply service (SSS) consumers) would be included in the "Regulatory" charge. The concern raised is that retailers must include these costs in their commodity price offering to potential customers and the current SSS Administration charge should therefore be included in the RPP price so that consumers could compare "apples to apples" in terms of the commodity price.

Another WG member suggested that this would not be possible because the "standardized" bill was determined by a regulation. It was also mentioned that moving one commodity related cost out of the “regulatory” charge would likely place us on a slippery slope since there are many other such costs (e.g., ancillary services) included in the “regulatory” charge. It was noted that the appropriate time to address this issue would likely be the consultation on code amendments, as this particular consultation will also involve amendments to the Retail Settlement Code.

This concluded the WG discussion on a “conventional” meter strawman. As mentioned above, the full preliminary WG strawman for conventional meters is included in the attachment to these meeting notes.

Smart Meter RPP Presentation

[Note: This presentation is also posted on the OEB RPP web page].

Navigant then began a separate presentation which switched the focus from “conventional” to “smart” meters within the context of the RPP.

The presentation outline includes: assumptions, considerations and key questions for smart metering (SM); Ontario price history and time of use (TOU) considerations; the impact and allocation of the global adjustment; critical peak pricing; variance recovery options; and the applicability or transferability of “conventional meter” strawman elements.

Navigant explained the assumptions made for a SM strawman. SM deployment would be consistent with the Board staff update included in the October 8th meeting notes. Deployment will also likely focus on larger customers first and will be mandatory for the selected customers; customers will not be able to remain on the RPP for “conventional meters” after having a smart meter installed; SMs will be capable of measuring hourly consumption and will have bi-directional communication capability; and the recovery of SM capital and installation costs is outside the scope of RPP WG.

Navigant also noted that the spot price pass-through will be available to all RPP consumers, but only by opting out of the RPP. In addition, as more RPP consumers are shifted onto SMs, the Net System Load Shape (NSLS or total LDC load less interval metered load) will likely change, but the impact of any NSLS changes can be predicted and adjustments can be made to mitigate the variance.

A WG member noted that, in the future, it may not be spot price pass-through that is the applicable option outside of the RPP. Instead, it will likely be the price determined in the day-ahead market (DAM) which is to be introduced in the relatively near future by the IMO.

Navigant also highlighted that, in addition to the other RPP objectives discussed to date for conventional meters, future discussions on SMs will also need to take into account an additional objective — encouraging load/demand management. Accordingly, the WG will need to determine how important this objective is relative to the others (e.g., cost reflectivity, price stability, customer acceptance, etc.).

Navigant also noted that, in terms of time-of-use (TOU) considerations, the traditional 7 a.m. –11 p.m. period likely remained to be the best definition of “peak” periods. It was also raised that a decision for the WG will be whether peak and off-peak prices should vary by season. For example, a “super-peak” period in the winter and/or summer, from noon – 6 p.m. in the summer and 6 p.m.–10 p.m. in the winter.

A working member suggested an approach for the smart meter (SM) RPP that the WG may want to consider. It was comprised of the following. For each billing period, the LDC would calculate: (1) the “conventional” meter RPP price X the customer’s total consumption; and (2) the customer’s actual hourly consumption X the weighted HOEP. Each would result in a different energy charge and the customer would be billed the lesser of the two results. As a result, the “conventional” meter RPP price would essentially serve as a cap for SM RPP consumers.

The presentation also included two charts which illustrated hourly prices for each season. The only difference between the charts was that one covered “only weekdays” and the other reflected prices for “all days (including weekends)”. The most notable difference is that, for the “winter”, the “only weekdays” chart showed a double peak at about 9 a.m. and 9 p.m., whereas “all days” had only a single peak price that was pronounced in the evening.

Navigant also clarified that references to “shoulder” months in the presentation material referred to “April/May” in the spring and “October/November” in the fall.

There was only time to cover a limited number of slides before the WG meeting came to an end. The WG will resume this presentation at the next meeting and Navigant requested that the WG members review the remainder of the presentation as homework and to also give some thought to 2 significant recommendations that will need to be made: (1) How many time intervals or buckets should there be for each day with different time of use prices?; and (2) To what degree should these time of use prices differ? ***[Action: WG members to come to the next meeting prepared with suggestions on these two questions. Navigant sent an e-mail to the WG members following the meeting requesting that they consider all of the questions on the final page of the presentation to prepare for the next WG meeting].***

Future Meetings

Thursday, November 4th (9:00 - 4:30)	-	OEB North Hearing Room
Monday, November 8th (9:00 - 4:30)	-	OEB North Hearing Room

Date Finalized: *November 9, 2004*

Prepared by: *Chris Cincar, Ontario Energy Board, 416.440.7696*

Attachment

Draft Working Group Strawman for Conventional Meters

Price Adjustment

- Price adjustment is an integrated process
- Price adjustment components
  - Adjust base rate to recover the 12-month forecasted cost of RPP supply over next 12 months
  - True up to reflect accumulated unexpected balances in the RPP variance account
- Price adjustment process
  - The difference from the actual cost of electricity and the forecast for the previous 3 months is tracked and entered in a purchase variance account
  - Every 3 (6, 12) months the RPP price is set based on a 12 month forecast of RPP supply cost
  - Along with the rebasing of prices every 3 (6,12) months, establish a price adjustment that is intended to zero out the variance over projected consumption for the following 12 months
    - Except that favorable variances are not zeroed out
  - A threshold amount can be used to determine whether the price adjustment is significant enough to warrant implementing the change
  - Threshold is determined as a percentage of the existing price or an absolute number
- Price adjustment applied equally to any tiers
- In the event that the true ups are less frequent than 3 months, some working group members favoured providing for an interim adjustment if the variances exceed some trigger value
- Trigger suggestion:
  - Size of RPP variance account relative to forecast in conjunction with forecasted variance through to end of year
    - (RPP supply cost)
- Maximum price increase per year:
  - Not recommended
  - The working group recognizes the Board's discretion in setting rates, and that it will consider impacts on the total bill

Calculation period

- Calculation period will be derived from the notice period. It is accepted that the calculation will generally involve some estimation or forecast of some data, in order to maintain the price adjustment and notice timetable

Notice for price adjustments

- LDC notice (15 days for price implementation, assuming no structural change)
- Customer notice
  - Minimum of 30 days before effective date of new price
    - From OEB by public notice

- From LDC by public notice (e.g., website) or bill messaging as soon as possible after it receives notice

Calendar adjustment

- Recommend to the Board that changes affecting eligible customer rates be synchronized

Seasonality

- The working group considered seasonal prices, and did not recommend them due to uncertainty over seasonality patterns in prices, considerations of price stability, administrative costs, and consumer comprehension and acceptance

Second-year transition

- The working group determined that the price adjustment mechanism described in this strawman would deal with any anomaly between the first and second years of the RPP

Setting RPP price

- Price should be set so that the expected value of the cumulative variance over the coming year is zero

Tiers

- TBD

<u>Pros</u>

- Now exist. Anything else would require transition
- Promote conservation
- In absence of seasonality, only means to promote conservation
- Good transition to smart metering (in terms of customer understanding)
- Manages variances better (creates a mechanism likely to take prices closer to supply cost when prices are high)
- Higher tier price communicates potential future price signal
- Generally more cost reflective
- Promotes migration to smart meters
- Incents larger customers to take competitive supply

<u>Cons</u>

- More difficult for customer to understand
- Current system creates cross subsidization across customer classes
- Creates inequities within classes (space heating and conditioning customers versus others)
- Difficult to design tiered rate without knowing what customers are eligible for RPP
- More difficult to bill and settle: issues of billing accuracy
- Differing system applications in different LDCs: proration of tiers
- Could deter DSM peak-shifting (because peak-shifting usually uses more energy) until SM
- Not always cost reflective
- Administratively difficult for some customers