Rate Design for Electricity Distributors

EB-2007-0031

December 12, 2007 Consultation Meeting Notes

These meeting notes are intended to provide people who did not attend the session with some of the information that resulted from participant discussions. The headings follow the agenda items. Not all discussion is reflected. They are not formal minutes.

Board staff identified several questions that should be answered through the project. These are identified in the notes.

Jurisdictional survey/ Environmental scan

Elenchus distributed a summary of research into innovative rate design around the world as background to the staff paper. That summary is available on the web-site as Jurisdictional Review.

The group discussed some examples of smart meters and rates.

- Several jurisdictions have smart meters in pilot or deployment, often in early stages.
- The UK currently has no Time of Use (ToU) rates.
- Several US utilities are not using the smart meters that have been installed for dynamic pricing.
- California seems to be the furthest along.
- In 2001 and 2002, Puget Sound Energy had a pilot of bundled rates that was successful in achieving conservation and load shifting. However, most customers (out of 300,000 involved in the pilot) paid more under ToU, primarily because the ratio of peak to off-peak prices was very low.
- In California, PG&E breaks out delivery and commodity because of competitive market.
- Several utilities in the US are actively dealing with rate impact and cross subsidy issues and matters because of the lifting of price caps and rate freezes.
- The U.S. Energy Policy Act of 2005 provides standards for time-based metering and ToU rates. The Act requires that Public Utility Commissions study time dependent rates but does not force them to implement them.
- France has a uniform tariff for all of its distributors. Also, rates were recently unbundled.

Response to questions:

- Norway has some amperage customer classes.
- Italy has demand based rates.

- The regulator governing Puget Sound Energy discontinued the ToU rate pilot after 14 months; while the reasons aren't entirely clear, it was noted that the Washington Utilities and Transportation Commission made a general finding that the ToU rates were not fair, just and reasonable, and the regulator further commented that the majority (94%) of the customers participating in the pilot program paid more under the ToU tariff than they would have paid under standard tariff service.

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Customer classifications

The following points were made during the Customer Classification session :

- The Large User class currently begins at 5MW of demand. However, technical service issue arises at about 3MW. The group did not have immediate suggestions as to where the boundaries should be. One possible solution is the addition of more intermediate classes but it was not clear that there was a cost justification. Demand levels could roughly correspond to use of the bulk/primary/secondary systems.

- Embedded distributors should be included as a customer in the appropriate underlying rate class since the service characteristics are the same.

- Service quality should be a cost based, contracted amount for services rendered since customers can provide for their own needs and equipment.

- Classifications could be based on service, bulk / primary /secondary. If that is done, however, customers with the same usage would have different rates. There was a suggestion that if they are connected at different voltages, the customers are placing the same 'demands' on the system that justify different rates despite the same usage. However, there was not general agreement. This approach would provide an incentive to new customer to make siting decisions that make efficient use of the existing system.

LDCs comments on these points were that:

- These classifications are not clear-cut for many distributors. As an implementation issue, it would be difficult to justify to customers and identify which customers would be in which classifications. Rate shock might be significant.
- The biggest problem is identifying the division point between bulk and primary. Primary/secondary is not necessarily clearer. But current cost allocation for customer class is roughly primary/secondary based.

AMPCO commented that rate design should look to the future development of the system. The payment system should reflect what part of the value system a customer is using.

ERA noted that if the distributors are providing the same service in a different way there may be relevant differences in the service provided. For example, service at a lower voltage means the distributor has installed assets that allow the customer to use the power at lower cost.

Large User customers

The following points were made during the discussion of large user customers:

- Consistency between distributors in terms of the rate structure would be advisable.
- Cost allocation studies and new rate structure could cause significant bill changes for these customers.
- Careful consideration of implementation issues and mitigation of rate shock would be necessary.
- Regarding the use of kVA as the billing determinant:, it was noted that transmission is still billed on kW. Other comments included:
  - AMPCO noted that service costs differ by kVA.
  - LDCs observed that some large customers do not have proper metering. kVA billing would have cost implications. Unknowns: cost of metering changes. There was general agreement that kVA is a better measure of cost causation than kW.
  - A transition mechanism would be necessary. i.e. If the charge is the same, the kW customers should get a small break until the meter is changed out.
  - Direct Energy noted analysis is required to the impact on the revenue of LDCs who have large user customers. It is also not clear that customers want this.
  - Toronto observed that transmission is billed by kW, distribution for large customers is billed by kVA.

With respect to embedded distributors, comments included:

- HONI bills distributors on kW but host distributors must keep the kVA at connection at 95%.
  Question for distributors: what % of your supply is from a host distributor? Many participants support the view that the charge for embedded should be the same as large customer charge.
- Waterloo North Hydro, however, indicated that embedded distributors may not fall into large user class.
- FOCA and AMPCO noted that the load profile of embedded distributors is not the same as a general customer.
- HONI suggested that embedded distributors should fall into a customer class based on each delivery point.

- Waterloo North Hydro noted that some distributors have multiple embedded delivery points. Rates must avoid pancaking where there is wheeling between delivery points.
- Multiple delivery points should have a diversity benefit. Do not penalize an embedded distributor when delivery points are compromised by the host distributor. Issues are the same for some Large Customers.

Question: what are the implications of alternative treatment of embedded distributors?

Small volume customer classification

the general view is that Small volume = residential + GS<50 + some GS>50

Elenchus raised the idea of creating mixed classes for small volume customers rather than separating them by Residential and General Service. There might be more class divisions than currently in small general service. Comments were:

- Union Gas noted that previously, the gas utilities did not differentiate residential customers as a group. The Board pressured the gas utilities to break General Service into distinguishable groups because of cost allocation issues. [Board staff should research the reasons for this decision.]
- EDA suggested that combining the small volume rate classes would eliminate the potential to cross subsidize residential customers.
- Elenchus added that the differences at the extremes of the end-use classes [i.e. a small bungalow and a monster house or a General Service customer at 50 kW and a General Service customer at 2500 kW] are bigger than the differences between classes. Smart meters means we can stop using a load shape assumption as a proxy for actual usage. A mixed class would reduce differences between the extremes of classes reducing boundary issues.
- BLG noted that under the old Ontario Hydro rates, up to 10% above costs could be added into the end rate block (the final declining block rate was higher than cost). This may have been intended to subsidize residential and small volume users.
- FOCA observed that there is an added cost for 3 phase customers (generally GS as opposed to residential customers). High level General Service customers have more expensive meters.
- GEC suggested that there could be fixed monthly customer charges that differentiates sub-classes for customer-related costs differences such as 3 phase service or metering. Other charges would stay the same (basic MSC and variable rate).
- Burlington Hydro raised the concern that sub-classes based on service characteristics (metering etc.) could lead to underutilization.
- HONI observed that there is currently legislated subsidization for rural, residential customers. There are always questions regarding the ability to distinguish those eligible, for example, owner-occupied farms.

- The Ministry noted that some parts of the *Electricity Act, 1998* and the *Ontario Energy Board Act, 1998* and several regulations made under them use the customer rate classes to determine eligibility e.g. RRRP and RPP. These things may not be easy to change.

Streetlighting, Sentinel Lighting, USL, Seasonal rates, Remote community rates

There is a question as to what changes are contemplated for these classes in this process.
EDA notes that municipalities may push for ToU streetlighting rates i.e. a discount for off-peak use. The cost allocation filings have suggested that most current streetlighting rates are below cost for the distributors.

Breakout sessions

A. ToU based rates

This approach blends hourly prices to provide a more stable price signal. Energy / demand over several hours or daily peak demand. For illustrative purposes, Staff presented a sample of what a variable ToU-based rate might look like assuming the monthly service charge was remaining the same and the intent was to recoup the same revenue.

Pricing Model	Consumption	Period	Price
Flat price	1000 kWh	All hours	0.0159 $/kWh
Broad peak	520 on peak	7 am to 10 pm	0.0233
	480 off peak	10 pm to 7 am and All weekend	0.0078
Narrower peak	230 on peak	Noon to 5 pm	0.0327
	770 off peak	5 pm to noon and All weekend	0.0109
1 hour peak	1.6 on peak	1 hr customer peak	0.0475
	998.4 off peak	Everything else	0.0158
Equivalent to demand charge	1.6 on peak	1 hr customer peak	9.94 $/kW
	998.4 off peak	Everything else	0

Group presentation

Pros	Cons
Will need a variance mechanism to correct for revenue variability (coordinate with IRM)	Lacks reflection of cost causality (distribution system peak and non-coincident peaks)
Reinforces commodity price	Increased distributor risk (trades off with Return

signal	on Equity number)
Simplicity of bill (assuming match to the RPP-ToU periods)	Difficult to predict what customer response will be (pilots will be needed)
Comprehensive to customers	Doesn't address GS = 50 kW boundary issue
	May force regional rates (north and south) and affect harmonization
	Customers with retailers may have a mix of billing determinants

The group assumed some policies as givens in order to make implementation feasible.

- The time periods should match the periods used for the commodity billing of RPP i.e. 3 time periods and seasonal changes
- Transmission should follow and also be time dependent
- OEB will need to address the revenue stability issue
  - Increase the RoE
  - Allow update of load forecasts during IRM cycles
  - Variance account could be a Y-factor in IRM
  - A smaller differential between on- and off-peak periods
- There will be some fixed monthly customer charge
- There will be some charge for off-peak hours (and on-peak hours)
- Pilots will be undertaken to gain info on customer response. These must be mandatory in order to get the non-keeners.

The group made recommendations to address some of the cons identified above.

<u>Cost causality</u>
A more narrowly defined peak (i.e. rates for mid and off peak are the same) better approximates a demand charge for <u>most</u> typical customers but it increases risk from shifting since there are more off-peak hours. There will always be outliers and exceptions that do not have a typical load profile.

<u>Boundary issue</u>
Lower the demand boundary to 20 kW or create a GS 20 kW to 50 kW class.
Lower the demand boundary all GS customers.
Create a new GS 20 to 50 kW class that has ToU rates.

The group identified questions that will need to be answered as we proceed.

- What time periods would best capture the hours of capacity concern?
  - Assuming that the time periods will match the RPP periods (one of the givens), can the prices be the same in some time periods (i.e. off and mid equal or mid and on equal)?
- Are we moving to Real Time Pricing that abandons ToU periods?
- What is the appropriate/economic price signal?
  - What is the rationale for ratio of rates? Is there experience in other jurisdictions? [Elenchus to investigate]

    - Should the ratio of rates differ between any LDCs?
    - Should the LDC decide what the ratio of rates will be? Or should the OEB establish an acceptable band and the LDC justify its choice. (There was general agreement that the Board should dictate a ratio.)
    - Should ratio of rates differ between northern and southern LDCs?
    - What about LDCs on the border of the regions?
- What is the cost (LDC implementation costs and regulatory costs) to benefit (conservation achieved and permanent) ratio?

<u>Fixed/variable split</u>
The group discussed the appropriate ratio of fixed monthly customer charge to variable rates. In the cost allocations studies, staff had identified three potential levels for the monthly service charge:

a) avoided costs (the cost of metering and billing)
b) a + administrative overhead allocated to classes
c) the minimum system concept (a + b + the cost of wires but no demand capacity)

In the Report of the Board, <u>Application of Cost Allocation for Electricity Distributors</u>, the Board decided that a) would be the floor and c) the ceiling level for monthly service charges.
The group agreed that a) sent a conservation price signal and that c) represented more of a cost causation concept and provided greater revenue stability to the distributor. There was no agreement as to the "right" answer. The question represents the tension between conservation efforts and utility risk.

General Discussion
There was debate because of distributor concern over exposure to revenue volatility. Discussions going forward should include mechanisms for rate stabilization.

System loads are utility specific but generally break on regional lines: North (winter peaking) and South (summer peaking).

The differential ratio may reflect either arbitrary social engineering or an analytic cost basis. Important policy questions include:

- Should the price signal deviate from costs.
- What happens if customers don't respond?
- Where does social engineering become "unfair."

Question: The jurisdictional study should look at what ratios are used (and absolutes) and what responses are.

It was also noted that the fixed/variable split affects the risk to distributor and affects what spread on peak/off is acceptable. Variance account solutions have a regulatory burden aspect that has to be addressed if the solution is to be acceptable.

B. Capacity / Demand

Group presentation: Demand Charge

The primary design consideration for a demand-based charge is the time period for which the demand serves as the billing determinant. In particular:

- Is coincident or non-coincident peak used?
- Is the annual, quarterly, monthly, daily or some other peak used?
- Are 5, 6 or 7 days of the week considered?
- Are all hours of the day considered?

In addition, consideration has to be given to whether there is a single rate charged if more than one peak period within the year is used. A possibility is a "Time of Use" demand charge that is based on different KW rates that apply to different peak periods.

Several concerns were identified with using Dx demand charges.

- Unbundling of Dx rates should be avoided as it would result in excessive complexity.
- HONI noted that that it may be necessary to retain density based rates even if the current energy charge is replaced with a demand charge.
- Certain designs may require a "ratchet" mechanism to ensure that the appropriate rate is charged throughout the year.
- The impact of any specific demand charge proposal on LDC revenue certainty needs to be assessed (i.e., using the modeling of bill and revenue impacts).
- In order to achieve a customer response to the demand charge price signal, the current approach to a simplified bill will have to be re-examined.
- Due to legislative/regulatory constraints (i.e., rural rate assistance; RPP) it may be necessary to maintain separate Res and GS classes, even if they have the same demand charge.
- A demand charge would not replace the basic customer charge as well as the energy charge; hence, the fixed/variable split will still be an important policy issue.

Group presentation: Capacity Charge

The group discussion resulted in general agreement that the introduction of a capacity charge for small volume customers is not practical for many reasons.

- Using a customer's service connection as the billing determinant would be too crude an indicator of the customer's capacity requirement.
  - Existing service connections reflect building codes and developer decisions, not the capacity required by a household.
- Limiters could be installed to enable customers to choose their capacity but the cost of doing so could be an serious impediment.

- A capacity charge would be most appropriate for new construction on a going-forward basis since the market could respond to the price signal; however, it would raise serious equity issues if new units are billed on a different basis than existing housing.
- Even for new construction, customers may not be able to respond to the capacity charge efficiently without changes to building codes. Minimizing the capacity of service could create fire hazards due to overloading, as well as inconvenience and unreasonable costs if customers wish to change their service capacity.

General Discussion
Short run costs are not variable based on design capacity but embedded. Long run costs are variable and demand related. Avoiding incremental costs requires a price signal. There will be costs to accumulate data and allow customer choice.

Because of regulation and legislation, it may be necessary to maintain separate rate classes even though the variable rate may be the same.

Density rates may have to be carried through where they have a cost basis.

The fewer the demand periods on which charges are based, the less the incentive to conserve for the rest of the periods.

An LDC would have to forecast the daily buckets and seasonal buckets on a forward basis to come up with revenue requirement. This requirement increases risk. It also results in added complexity of forecasting and concomitant regulatory review.

Next steps

For the next meeting, Board staff were to clarify the difference in scope of this project and the Distributed Generation project with regards to distributed generation.