Rate Design for Electricity Distributors
EB-2007-0031

January 16, 2008: 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.

Follow-up on ToU pilots from the Environmental Scan

During the previous meeting, the participants requested information on ratios and absolute prices in ToU pilots in other regions. Elenchus provided some information in the form of handouts (available on the web-site as *Update of Environmental Scan*). Elenchus is in the process of getting information from Energy Australia, a distributor in Australia that is implementing smart meters and has separate distribution rates and a default ToU rate for small volume customers. EA is piloting dynamic pricing with a CPP element under another name. It includes 2 price points above the off-peak level: CPP high is $2/kWh and CPP medium is $1/kWh. EA anticipates that $1.5/kWh will be the single optimum price.

There was further information on the Puget Sound ToU pilot and aftermath in the handout.

Elenchus presented some information on the California State-wide Pricing Pilot involving 3 Investor Owned Utilities in California testing demand response to dynamic pricing. Analysis shows the results to be statistically sound. Elasticities discovered in the study have been applied to pricing in other regions.

In Arizona several distributors offer ToU rates including demand charges. In Florida there is a strong emphasis on load control with an interactive technology system proven in earlier pilots. Gulf Power ration of peak price to off-peak price is 1.85. Mid price to off-peak price is 1.09.

AMPCO asked Elenchus to try to determine how distribution costs are being factored into these bundled rates.

As previously noted, examples of rates in other jurisdictions are usually for bundled rates. No one is studying the effects of ToU rates in distribution systems alone.

Some participants questioned whether adding ToU distribution rates to ToU RPP will gain any more response. The environmental scan should look for the effectiveness of elasticity on the margin as well as total elasticity. ERA stated that there are technology-related questions regarding how to get signals to customers, individually and automatically.

Elenchus reminded participants of the previous discussions. One objective of the process is a bill that reflects commodity costs and distribution costs. The objective would be a ToU design that recognizes the cost drivers and tries to derive a practical implementation for customers. ToU is a rough proxy for demand which is the cost driver. LIEN noted that long run distribution costs may track ToU better than short run costs indicate.

FOCA stated that small volume customers like fixed bills to the point of distributors offering equal billing programs. Retailers offer similar programs. Board staff noted that small volume customers also like low bills and billing that is linked to usage. AMPCO noted that equal bill combined with a statement of use showing how use is affecting billing is common in many jurisdictions.

There was a discussion of information sources available to the Board to help in determining the appropriate variable component of distribution bills.
1. Cost allocation identifies cost of providing energy.
2. The Total Resource Cost Test used in evaluating conservation and demand management programs has information on avoided costs.

Distribution System Losses

Audit project

Bill Cowan, Chief Regulatory Auditor, presented information on a business plan project under the Board objective of utility cost effectiveness. Raj Sabharwal is one of the staff team members. Distributors currently report information on efficiency regarding line losses as part of the RRR requirements. Distribution system losses are defined as energy in (from the transmission system) and energy out (in net delivery to customers). The overall objective of the project is to develop Board policy on how to address or encourage distribution performance improvements on losses.

Reported amount of distribution loss in aggregate for 2006 was 4.2%. For 2005 it was 3.9%. AMPCO noted that Ontario demand in 2006 dropped relative to 2005, but the peak increased. On its face, this seems to substantiate that losses are linked to demand, since peaks were higher in 2005. Individual LDCs go up to 12%, the main grouping of distributors have higher losses than than average of the entire group. There could be differences in how distributors calculate unbilled amounts. The survey is trying to understand these differences.

The project begins with a questionaire on practices sent to distributors. The questionaire was not sent to any of the distributors undertaking a 2008 Cost of Service rate proceeding or those who have recently been audited. The remaining distributors include more than 50 companies with a good balance of regional, size and rural/urban representation. Distributors in the excluded groups can be included if they want to. The questionaire is comprised of open-ended questions and specific questions. The intent is to identify barriers to addressing performance improvement and suggestions for overcoming those barriers. There are technical and non-technical losses. Technical system losses are due to physics. Processes for accurate meter reading relate to system losses. Sources of non-technical losses include meter issues, customer cut-off for non-payment (i.e. if payment for the energy delivered is never recovered), and theft.

The project team will integrate answers with RRR information. There will be a generic report in March. Information will be grouped and aggregated in order to derive meaning from the responses.

CNPI noted that increased distributed generation has an impact on losses. Some DG projects have the potential to increased losses on the system. The Audit team agreed that system configuration in general is a factor to loss. In fact, the relationship of losses to demand is specific to system configuration and loading. Smart meters will provide more information regarding dynamic loading and hourly losses.

The Audit team confirmed to Pollution Probe that a study of marginal losses at system peak which tend to be much higher than average losses is out of scope.

ERA noted that the Board has yet to identify to what extent is the system loss is controllable and how distributors could be encouraged/rewarded for controlling those losses.

Losses and Rate Design

SEC questioned who takes the risk of losses. The group noted that how the losses are being accounted for is a different question than how they are being billed. Veridian noted that charging for losses should be linked to accountability. LIEN suggested that closer matching of the charge to the costs could provide revenue stability for distributors.

Enersource noted that currently losses are related to commodity. Distributors charge for losses to cover the commodity bill from the IESO and pay the generators. On the bill, the loss adjustment is applied to the usage for energy. Green Energy Coalition suggested that instead of grossing up the usage the bill should gross up the charge.

There is the possibility to link loss factors to RPP prices or to link loss factors to distribution ToU prices. EDA expressed concern about how often the loss factor changes. Currently a distributor can apply to change its loss factor as part of a Cost of Service application. The distributor must provide justification.

Direct Energy stated that customers don't understand the concept of system losses. A significant amount of customer centre time is spent explaining losses on bills. More complex designs will make this worse and we must be sure that the incremental demand response is worth the cost of implementation.

Power Workers Union highlighted that once the roll out of the smart meters is completed, time of use ("ToU") usage readings from the smart meters will only provide data that will enable the calculation of distribution losses for each ToU period on average basis. Since customers are connected either to primary or secondary circuits, the calculation of the related losses also require usage data to be collected from meter readings at the appropriate facilities level of the distribution system (e.g. distribution stations, transformers, primary circuits and secondary circuits). It is too difficult to calculate losses on a customer basis and should be done on the distributor level not customer level.

Enersource noted that, currently, we do not have the information to quantify the difference in losses during peak or off peak. We should in the future be able to differentiate losses by time period based on smart meter information. Non-technical losses are not load or time dependent. VECC pointed out that non-technical losses are not time dependent and not driven by price signal. However, distribution planning engineers should be able to estimate time-dependent losses for a first-order approximation based on the relative movement of load and losses.

Elenchus stated that one objective of the staff report will be to identify the information gaps that need to be filled for implementation.

Class specific losses

Elenchus asked whether, since losses vary with the line voltage, there could be a correlation to service and therefore customer class. FOCA noted that HONi has different loss factors for the bulk primary and secondary systems. Toronto Hydro noted that it does too. This results in large users having lower losses.

Location specific losses

Elenchus asked, given losses specific to location, whether losses could be correlated to density since rural customers tend to be on longer lines. LIEN felt that it would be difficult to calculate. VECC added that, in 2008 Cost of Service applications, distributors have said that newer sub-divisions can be farther from transmission connections. However system changes over time may make this difficult to track and take into consideration.

Veridian noted that as part of applications to merge, distributors have to explain what advantages customers will get. Merged utilities can choose (or be ordered) to harmonize rates and losses.

VECC stated that, currently, if losses are above 5%, a distributor has to explain and file an action plan to address.

Potential for Sub-classes

Interruptible

EDA stated that the legacy view of interruptible rates is that they are freebies for customers. Customers received discounted rates but were rarely, if ever, disconnected. Therefore having interruptible rates should not be mandatory. A distributor might like to exercise the option when it has a major constraint. It would be fairly customer specific on an economic, contractual basis rather than a class since it would be highly specific to a location and the system configuration.

LIEN suggested that an economic justification would have to be reviewed by the Board. AMPCO suggested that if customer gave a reasonable proposal to a distributor there should be a process by which the distributor was required to consider an interruptible arrangement rather than building assets.

FOCA noted some examples of small-volume interruptible programs e.g. the former water-heater control program and the current peak savers on air conditioners that gives a general benefit. SEC said that there are a variety of interruptible options available. These are demand response programs and should not be enshrined in rates but on a contractual basis. PWU felt that interruptible rates should only apply to customers of certain size, e.g. over 300 kW and that the interruption should be subject to procedures established by contract. The FERC Cost of Service Rates Manual[1] has an example of economic calculation for interruption (Interruptible Rate Computed as Derivative of Firm Rate).

Service standards

The discussion was whether there were cost reasons for different classes based on service type. FOCA noted that HONi has different charges for 3 phase service compared to 1 phase service but not based on meter type. CNPI stated that metering costs can differ, e.g. instrument class meters are more expensive. They generally correlate to demand or service connection. In general, costs increase with service. This argues for more differentiation in rate classes to link customer classes to cost drivers.

[1] http://www.ferc.gov/industries/gas/gen-info/cost-of-service-manual.doc

In some cases this is a customer choice but is covered through the connection cost, not the rate.

AMPCO noted that the service connection size is dependent on expected demand. A distributor should be able to recoup additional ongoing costs as well as additional capital contribution on a contractual basis.

Distributed Generation (Load Displacement Generation)

Staff provided an update on the scope of various Board processes with regard to distributed generation issues. This was subsequently explained in the Board letter available on the website as *Streamlining of Issues*.

CNPI noted that to guarantee service to a customer, a distributor has to have a service connection ready to accommodate the full load if the load displacement generator (LDG) is down. This can be defined as firm standby service. Toronto Hydro noted that the LDG customer pays a standby rate when it generates. If the LDG goes down for more than 1 hour in the month, then it pays standard demand charges according to it customer class. It is one or the other. Enersource noted that, on a contractual basis, a menu of distribution services can be offered.

There was general agreement that standby rates do not apply to customers with generation of less than 500 kW. For larger customers, distributors and customers contract for capacity holding services (firm standby service). To the system, an LDG customer can looks like a load customer with bad load factor. The LDG customer may not take full load at any time but standby capacity is still there. HONi noted that an embedded distributor with a merchant generator looks like LDG to the host distributor.

EDA stated that one typical way of dealing with LDG customers who do not want to pay standby charges for the total load is to contract for firm standby service for contracted demand that is less than the total load. If the customer fails to stay within the contracted demand, the distributor will charge the incremental rate back to some point (one year or installation, etc.) If a distributor is holding capacity but not charging for the assets, then other load customers are subsidizing the LDG customer.

Elenchus asked if there is any credit for diversity in LDG loads or location. Currently, capacity holding is always on a customer basis, rather than on a local system basis. EDA stated that it is always difficult to define when a customer is incremental and that therefore services should be priced on the margin.

There is a link between on-going rates and connection costs. If the customer pays the connection costs, then the rate can be lower. Paying for more expensive connections through an extra capital contribution may not serve all situations and may not cover all OM&A system.

GEC suggested that the Board should identify what options the distributor is obliged to provide, breaks for off-peak use etc. This would help to overcome conventional thought that distributors are resistant to LDG. The Board should define minimum level of offerings to simplify the contracting process. Enersource suggested that the TransCanada and Union Gas overrun service charges for authorized and unauthorized overrun of allotted capacity could be a good basis for looking at standby rates.

GEC stated that it is similar to the transmission charging decision on net billing compared to gross billing. Changes in technology may overwhelm this decision.

Distributed Generation Classes

The OPA noted that there are tremendous differences in what underlying class distributors are assuming for generators. OPA would like to see Board direction on customer classes for generators.

Previously, HONi had proposed to waive the fixed customer charge for small generators and charge only a volumetric rate. HONi has the most Standard Offer Program applications both by capacity and number. E.g. Toronto Hydro has hundreds of applications for solar SOP under 3 kW. Approximately 30 distributors have at least one project.

HONi noted that it has filed separate customer classes for generation as part of the cost allocation study. It used hourly load profiles for its DG customers and identified a diversity benefit for those taking only station service.

VECC noted that there are many customers who have fairness issues with regard to customer charges. Setting aside larger issues to solve the distributed generation problem is not fair either.

Other issues:

Harmonization during IR periods would be very difficult because of customer numbers in customer classes. Rate harmonization could be proposed in a rebasing year and mitigation could take place through an IRM period.

The transformer ownership allowance is different than the unit costs identified through the cost allocation. The transformer credit should be changed. However, the cost allocation methodology was questionable. There was not agreement as to whether it was a rate class or sub-class issue.

Modelling

Elenchus reminded the group that the computer model developed will be used to identify rate impacts of specific scenarios in the staff paper. If participants would like to see specific scenarios modelled, they can request it to Rate.Design@oeb.gov.on.ca. It may not be possible to accommodate all requests with the data available but they will be considered.