The Voice Of Ontario's Electricity Distributors

May 30, 2008

Board Secretary
Ontario Energy Board
P.O. Box 2319
27th Floor
2300 Yonge Street
Toronto, ON M4P 1E4

Via Board's web portal and by courier

Dear Board Secretary:

Re: Board File No. EB-2007-0031
Rate Design for Recovery of Electricity Distribution Costs

The Electricity Distributors Association (EDA) is the voice of Ontario's local distribution companies (LDCs). The EDA represents the interests of over 80 publicly and privately owned LDCs in Ontario.

The EDA's written comments on the Board staff's discussion paper issued on March 31, 2008 are attached to this letter. The EDA strongly recommends using demand as the basis to define customer classes since we believe it would not be practical to use the 'actual connection voltage' as the basis of rate classification.

In addition, the EDA recommends introducing non-coincident monthly demand as a billing determinant for the Residential and General Service < 50 kW classes and retaining the existing demand charges for the other classes.

Yours truly,

"original signed"

Richard Zebrowski
Vice President, Policy and Corporate Affairs

Attach.

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EDA's Comments on OEB staff discussion paper
Rate Design for Recovery of Electricity Distribution Costs

The EDA agrees that the introduction of smart meters will radically change the information available for residential and smaller general service customers (<50 kW) and that this additional information would provide an opportunity to re-examine the assumptions, simplifications and proxies that were used in the past for designing distribution rates.

The EDA supports the Board in adopting the following principles for the purpose of rate design:

- Full cost recovery principle – The level of distribution rates should be sufficient to recover the revenue requirement of each distributor.
- Fairness principle – Customers should pay rates (for distribution service) that reflect the costs they "cause" to the distribution system.
- Efficiency principle – Distribution rates should encourage customers to efficiently utilize the existing distribution system and should encourage new customers to use the system in ways that lead to rational growth.

In addition, EDA members strongly believe that distribution rates should be based on distributor costs, and *not* on any other factors, such as

- Economic development (e.g., special rates for certain threatened industries)
- Conservation in other parts of the electricity sector (e.g., using distributor rates to encourage energy/kWh conservation)
- Social equity considerations (e.g., special rates for low-income users).

There are other, more direct, means available to achieve these goals without distorting electricity distribution rates.

The following comments on the OEB Staff Discussion Paper of March 31, 2008 entitled "Rate Design for Recovery of Electricity Distribution Costs" are based on input received from EDA members.

Customer Classification

The EDA notes that the OEB Staff Discussion Paper provides two approaches to define customer classes: the existing approach which uses the size of the customer and load profile differences and a new approach based on the connection voltage.

The existing approach would result in at least three volumetric classes: small volume, intermediate volume and large volume.

The connection voltage approach would result in four classes: secondary – single phase, secondary – 3 phase, primary, and subtransmission.

The Discussion Paper notes that customers are not always able to choose the voltage at which they connect to the system and the available options depend on the facilities in place. As a result, customers with identical power requirements may be served at different voltages simply due to distribution facilities that are in place to serve their location. The paper notes that this suggests that customer classes should be based on customer volume, with class divisions based on notional optimal connection voltage.

The paper then points out that it may be fair to place customers with identical power requirements in different rate classes if they are served at different connection voltages because customers served at higher voltages incur higher on-site costs to step down the voltage for use. The EDA believes that the present approach of providing transformer allowance credits to customers that incur costs to step down the voltage adequately addresses this issue.

The EDA supports the existing classification methodology. The historic development of distribution systems in Ontario has resulted in a range of different voltages in use. Distributors believe because customers did not have a choice as to their connection voltage, it would be unfair and hard to explain to customers that they would be paying more or less than other similar customers because of their voltage connection. Customers did not have the option to choose the voltage at which they connected to the distribution system. Customers were connected to the distribution system based on the facilities in place nearby in order to reduce connection costs. Customers connected in an older part of the distribution system may be served at different voltages than other customers, as distributors undergo voltage conversions to their system. For example, many distributors are undergoing a voltage conversion from a 27.6 kV 3-wire system with a 4 kV distribution to a 27.6 kV 4-wire primary system. In addition, there are distributors that have amalgamated distribution systems of different voltages. Consequently there are many situations where customers with identical power requirements are served at different voltages within the same utility. Distributors believe that customers would argue that they are being unfairly treated if they paid more based on their connection voltage. Classification methodologies must be acceptable to customers. The EDA believes customers would not support an approach that is based on voltage connection.

The EDA believes customers understand and continue to support a classification methodology based on size. The EDA recommends using peak demand as the basis to define customer classes. Differences in metering costs, customer services, typical service connection and other costs typically vary according to the size of the customer. Differences in distribution costs also vary with size as larger customers typically use distribution facilities at higher voltages. A classification on size based on peak demand informs customers that their peak demand is important as it determines their classification and costs.

The EDA would support three customer classes of small volume (under 50 kW), intermediate volume (50 kW – 1000 kW) and large volume (over 1000 kW). These divisions between classes are based on the understanding that costs vary with size, which was reflected in past practices. In addition, we would support the establishment of a residential subclass to deal with legislative requirements and also an over 5 MW subclass to recognize that their connection is typically at the subtransmission level. Other subclasses may be needed to establish standardized per-customer charges and demand charges for each subclass that will allow smoother transitions between classes as customer loads increase.

Interruptible Rate Class

The Discussion Paper notes that some stakeholders support the use of interruptible service as a tool for distributors to avoid expansion costs under certain situations. The EDA supports providing options to distributors but believes a separate rate class is not required. Distributors who have situations where interruptible customers would defer expansions for a certain amount of time could offer a rate discount to those customers that meet the eligibility requirements for interruptible service, which would include a demonstrated ability to interrupt a significant amount of load and situated in an area that would avoid the expansion. The EDA expects this rate option would be offered very selectively and only for a limited time.

Rate Design Issues

The Discussion Paper notes that a cost allocation study provides the best available indicators of how to recover the distributor's revenue requirement to ensure that relative cost responsibility among customers in a class is fair. A direct application of allocated costs would result in a monthly customer charge equal to 1/12 of the annual customer related costs for each class divided by the customer class numbers and a monthly demand charge/capacity charge equal to 1/12 of the capacity related costs of the class divided by the peak demand/ total capacity of the class.

The paper argues that rates based on cost allocated costs would not necessarily be efficient, easily understood by customers or effective in achieving various policy objectives. The EDA believes the resulting rates from a cost allocation study best tracks costs and these other considerations in our view do not justify a change in approach. The EDA believes demand/ capacity charges are efficient and are understandable by customers. The EDA believes demand/ capacity charges do not conflict with any policy objectives.

The discussion paper asks whether there is a necessary connection between long run variable costs and variable rates, and whether variable charges are an effective means of controlling long run variable costs in the rate-setting context. The paper then argues that distribution costs are variable in the long run and an appropriate long run price signal would result in a more efficient expansion of the distribution system. However, the issue is whether an appropriate price signal can be established that would recognize the short term costs of the distribution system and also encourage customers to recognize the long term implications of their consumption decisions. The price signal should be designed to ensure the customers are consistent, persistent and predictable in their behaviour. Short term responses to reduce load do not defer investments if the load returns at a later date.

As a result, the EDA believes consideration should be given to an annual non-coincident demand charge based on the highest non-coincident demand of the previous year. This annual demand charge would provide a strong signal to limit peak consumption in the long term and would better recognize the short term fixed costs of the distribution system.

Use of an annual non-coincident peak as the charge determinant does not perfectly reflect the short term fixed costs because annual peaks can vary from year to year in part because of weather. However, an annual peak is generally less weather-dependent than the alternatives (such as energy or monthly peak demand), because there is usually at least one very hot or very cold hour in the year during which the customer's demand reaches its design peak, even if temperatures during the rest of the year are more moderate. As a result, it more closely reflects the system capacity available to the customer.

The EDA supports the use of non-coincident demand as the billing determinant for the reasons given in the discussion paper. We agree that a distribution system does not experience a single coincident peak because the timing of the peak differs for different elements of the distribution system. In addition, we agree that customers would better understand how to limit their own peak usage whenever it occurs. A non-coincident demand charge determinant also reduces the possibility of customers by-passing their fair share of costs by shifting their peaks from certain hours.

The EDA notes that the Discussion Paper offers a criticism against using an annual non-coincident demand by noting that once the customer's peak demand occurs, the customer would not be concerned with limiting his demand subsequently in the year when the distribution system peak could occur. The discussion paper suggests that it may be preferable to use a demand charge on the customer's monthly peak demand in each month to ensure the charge is easily understood. The EDA notes that the monthly coincident demand is the existing approach for demand metered customers and may be better understood by residential customers in the near term. The use of a monthly demand charge could be an interim step towards the implementation of an annual demand charge. The EDA believes, however, that the annual non-coincident demand better reflects capacity available to the customer.

The EDA believes the rate design for all classes should be the same to facilitate customer understanding and to avoid the discontinuities as customers move from one size-related service classification to another. The paper notes that there is a gap whereby customers with demand over 50 kW but less that 200 kW will continue to have demand readings that are not time-correlated. We believe that distribution rates should not be time-correlated and that the billing determinants for both the under 50 kW and over 50 kW classifications should be the same, based on non-coincident demand and a customer charge.

<u>Distribution Rate Design Based on Time of Use (TOU)</u>

The EDA believes the non-coincident demand used for the charge determinant should be based on one hour. Intervals longer than one hour should not be considered as they would not be good indicators of distribution costs. As a result the EDA does not support a distribution rate structure based on Time of Use (TOU) commodity periods.

As noted above under the discussion of principles, the EDA believes goals to support conservation in other parts of the electricity sector and in particular commodity, should not be a basis for setting distribution rates. Distribution rates should be based on distribution costs and should encourage efficient and effective use of distribution resources; it is neither necessary nor desirable to skew distribution rates to encourage conservation of generation and transmission resources. The EDA believes that all of the various electricity supply cost components as presented on the bill should be reviewed and considered separately. Commodity pricing should not influence distribution rate design. There is no need to reinforce commodity price signals through distribution rates.

TOU distribution rates would increase the likelihood of customers bypass. Customers shifting their consumption from on-peak periods would be not paying their fair share of distribution costs if their peak demand was outside the TOU period.

<u>Rate Design for Embedded Distributors</u>

The Discussion Paper asks whether there is a need to maintain a separate class for embedded distributors. Given the EDA's view that distribution costs should be recovered through demand charges and customer charges, the EDA believes there is no need to maintain a separate class for embedded distributors.

<u>Rate Design for Load Displacement Generation</u>

The EDA supports the view that generation facilities of less than 500 kW not be treated as load displacement generators. The distributors can absorb the revenue loss from the demand reduction of load displacement generators as is done in the case of any other customer's fluctuation in demand. Individually these smaller generation facilities have an immaterial impact on the need for backup capacity.

The EDA believes customers with generation facilities larger than 500 kW should be required to pay for backup capacity held in reserve to serve their net load increase when their generation is down. Given the EDA's position that rates should be based on demand, the EDA continues to support the use of a contract charge based on the firm standby service with penalties for exceeding the maximum.

The EDA does not support a TOU price for load displacement customers as it does not address the recovery of backup capacity or the risks from unscheduled outages.

Load diversity credit

At present, the EDA believes there are presently little benefits from diversity between load displacement generators. For most distributors, the number of load displacement customers per feeder is very few. To obtain diversity benefits, there would need to be several load displacement facilities on a particular distribution facility. The EDA believes this issue requires further discussion to identify under what situations relevant diversity benefits could occur.

<u>Rate Design for Unmetered Scattered Load</u>

The Discussion Paper asks whether a separate unmetered scattered load class should be mandatory and the relative merits of billing for unmetered scattered load on the basis of customers and connections.

The EDA notes that it is neither practical nor economical to install a meter on every small scattered load. As metering technology changes, however, there may be opportunities in the future to meter these scattered loads cost effectively. As a result, the basis for charging for unmetered scattered loads should not be very different than for metered loads.

The EDA agrees that load studies could be used to establish the demand of these scattered loads but whether billing aggregation benefits should be allowed will depend on how they are scattered and their load profile. If the scattered loads are close together, such as streetlighting along a street, then there may be density benefits and lower associated connection costs, but the load profile of streetlights provides no system diversity benefits. If the scattered loads are not close together then the distribution benefits are lessened and should not be recognized. The EDA does not support the recognition of demand diversity benefits between scattered loads. As noted below regarding metered scattered loads, the EDA does not support recognizing diversity between loads not located on a single property.

The EDA notes that distributors presently bill their unmetered scattered loads either based on the number of customers or the number of connections depending on how the unmetered scattered load is actually connected to the distribution system. Therefore, it is not advisable to be prescriptive in formulating policies for billing unmetered scattered loads. The EDA recommends permitting distributor discretion for billing the unmetered scattered load to meet the individual customer requirements. The EDA believes most unmetered scattered loads are very scattered and in those situations a charge based on number of connections is appropriate. The connection charge can be set to recognize that there are no associated metering costs, and lower billing costs.

The discussion paper asks whether there is the justification for separate classes for street lighting and sentinel lighting. The EDA believes there is merit in establishing a separate class for streetlighting because streetlights are a unique load whose demands can be accurately established through engineering analysis without the use of metering. In addition, as noted in the paper, streetlights do not use the same facilities as other smaller loads and typically a large number of streetlights are connected to the distribution system through a single connection.

Rate Design for Metered Scattered Load

The discussion paper asks whether the diversity benefit associated with multiple locations should be reflected in the rates paid by customers with metered scattered loads, and whether customers with metered scattered loads should be able to aggregate their bills and be charged a single fixed monthly charge that reflects the reduced costs associated with the single bill.

The EDA is very concerned with the implications of redefining the commonly accepted industry practice for defining a customer. The practice is to define a customer based on an account, which is based on a meter connection and being on a single contiguous property. A change from this approach would lead to a slippery slope of determining who would be eligible to combine their load (e.g. who is the ultimate owner?). Treating two similar loads of the same class differently based on ownership of the load could be seen as discriminatory. In addition, there are no diversity benefits on the distribution system if the loads are connected on different parts of the distribution system.

The only savings obtained from issuing a single bill for multiple locations would be the costs of the bill. It would not reduce other customer related costs and would not save demand related costs. The EDA strongly opposes proposals to allow aggregation of demand of multiple locations for determining demand charges.

For the convenience of the customer, distributors could provide a common bill if requested. But the expected savings from a single bill will be minimal.

The EDA strongly recommends that there be no customer discrimination permitted by way of providing diversity benefit based on load ownership.

Revenue Recovery of Distribution System Losses

The Discussion Paper asks for the most appropriate way to adjust the commodity for distribution system losses. The EDA recognizes that losses do vary with system loading and consequently there is merit in considering a loss factor that varies and increases with the increase in system load. However, the EDA believes a varying loss factor can be complicated and will be more onerous to implement and therefore we believe further study is required.