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Ontario Energy Board
27th Floor
2300 Yonge Street
Toronto, Ontario
M4P 1E4
ATT: Kirsten Walli, Secretary

May 13, 2007.

Dear Ms. Walli,

Re: Review of Electricity Distribution Rate Design
Board File No.: EB - 2007- 0031

In accordance with the OEB's e mail and web posting of March 30, 2007, ECMI submits its comments on Board staff's Discussion Paper also dated March 30, 2007.

In considering the Board staff discussion Paper, ECMI has attempted to address the profound and significant issues and opportunities in an orderly and coherent fashion. Rather than narrowly focusing on the limitations of the existing customer classification system and rate design, ECMI has taken the "clean slate" to heart and included "An approach to customer classification and rate design (pricing)" which attempts to solve the issues raised by the paper in the context of electricity distribution in Ontario's marketplace.

Three paper copies are enclosed. Electronic copies in both Adobe Acrobat and Word have been sent this date by email to boardsec@oeb.gov.on.ca.

Requested contact details are as follows:-
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Respectfully submitted for the Board's consideration,

Original signed by R. White

Roger White
President

ECMI comments on Board staff Discussion Paper "Rate Design for Electricity: Overview and Scoping", dated March 30, 2007.

On pages 6 and 7 the staff Discussion Paper states:

> "As smart meters are implemented, more and more customers will have hourly data available. As a result, fewer assumptions may need to be made in allocating costs. In addition, this presents opportunities to design and implement distribution rates in a manner that was not previously possible."

If one examines this opportunity more closely in the context of pricing then principles like fairness, cost causality and equity may demand and not simply permit a fresh look at electricity pricing. It would be unfortunate if history and its attendant inertia preclude the Ontario market from seizing this opportunity.

The notion that a complex customer class system is warranted or required is not accepted by ECMI. Classes were a necessary evil when "perfect"(hourly information) knowledge on individual customer's use pattern was not available. For example, under a single price structure, general service under 50kW will be treated like residential customers.

With time of use rates there is no need for an inverted commodity price structure as time of use rates would more equitably do the job. With "perfect" capacity use information for both residential and general service customers, there is no need to price distribution system costs differently for these customers as time of use of the capacity use would be a much more cost effective and clearer signal to all customers.

It is often argued that long run marginal costs are in a fact a predictor of long run average costs. While building future inflation into existing regular distribution rates might appeal to some shareholders it is unfair to customers because it is not based on current costs. There is no guarantee that future long run marginal costs will be below or above current average costs. To introduce this disconnect between the accounting costs of the utility is unwarranted as it would eliminate the basis on which costs and rates are established.

On page 11, the staff Discussion Paper identifies Board regulatory policies as

- to have consistency in distribution rates in Ontario; or
- to appropriately address distributors' business risk.

Consistency in rates can be rate structures, rate levels and rate making policies. Multiple rate classes can mitigate against consistency in classes between distributors and lead to customer confusion when they are served in multiple jurisdictions.

As individual distributors face different business risk and different delivery situations it is difficult to imagine that regional rate schedules could fairly and equitably address the myriad of distributor's situations within the province. Distribution system customer density and load density are only 2 of the many factors which materially impact on real and unavoidable distribution system costs. It is therefore inappropriate to establish regional rate schedules other than on an optional basis. If an optional basis is provided, only those distributors which would likely benefit from opting in would choose to opt in. If this is the situation, then it might be hard for the regulator to suggest that fairness (cost causality) is behind the rates of a distributor which chooses to opt in. Similarly, if rate schedules are regional for those distributors where costs are below the established regional rate schedule the same argument about cost causality to customers would apply.

Distributors are in the business of providing deliveries to customers and in order to do that they have to build a delivery system. When any business goes to the bank and wants to borrow money, if it tells the bank that 10% of its revenue flows from one customer, then the business's cost of borrowing is often increased based on a potentially higher level of business risk due to the degree of revenue dependence on one or a few large customers. If these customers are in more risky business sectors or individually at higher risk, this can exacerbate the identified issue. Business risk may necessitate a recognition of scale in terms of the distribution delivery costs and distribution revenue to very large customers of a distributor.

An approach to customer classification and rate design (pricing)

Because numbered bullets will be referred to later in the document, the numbering is continued and should not be interpreted as significant but only for ease of reference.

If one looks at the traditional customer classification system in Ontario, the Large Use classification and the Intermediate Use classification where individual customers represent more than 10% of the distributor's load, scale recognition seems to dictate a separate customer classification.

If one then looks for atypical material users of the distribution system which are not generally end use customers in the normal sense these would include connections to:

1. Merchant Generators
2. Customers with material embedded generation
3. Embedded deliveries to other distributors, and
4. Customers with material load (scale adjustment if required)

Beyond the previous considerations it might be possible to group the remaining customers into one classification. If warranted bulk or subtransmission deliveries to material loads (individual customers representing more than 10% of the distributor's load or Large Use customers) could be established as a separate class or classes.

The staff Discussion Paper states on page 13 that customer classes should be homogenous. It also states on page 9 that class definitions should have no ambiguity in their application. It is apparent that existing classifications are not homogenous. This is true from a use of the distribution system perspective. Further, the current boundary within the General Service class set arbitrarily at 50kW generally produces material price differences between a 49kW of demand customer using 10,000kW.h of energy and 51kW of demand using 10,000kW.h of energy. These customers are virtually identical and using any homogeneity constraint appear to belong in the same class. The optics of this disparity have become apparent to many customers in the province and the arbitrary production of classes even if homogenous does not address the fact that when one considers the utility as a whole the customers within the utility are not a homogeneous group. Residential customers as a group are not homogeneous as they can include a senior system in an individually metered apartment using 300kW.h and an estate residence which is electrically heated both from a space conditioning perspective and the Olympic sized pool on the premises producing a use of 20,000kW.h per month. Clearly homogeneity should be a requirement for the establishment of separate classes outside of the total (all customers) utility classification if more than one class is contemplated.

What is important to customers, distributors and regulators is that rates are established on a cost causality basis. Classifications blur the direct linkage between cost causality and rates. A careful reading of Veronica Irastorza's article, "New Metering Enables Simplified and More Efficient Rate Structure" in *The Electricity Journal*, December 2005 noted on page 5 of the staff Discussion Paper, rightly indicates that the universal introduction of Smart Meters produces huge opportunities for the electricity production and delivery business and its customers. "Perfect" knowledge about the use patterns of each customer permit a direct linkage between cost causality (from a distributor's perspective the need for distribution system delivery capacity) and pricing to customers.

This can be readily achieved through the combination of a service charge (adjusted for metering type, billing & collecting considerations, and delivery configuration if appropriate) and time differentiated variable rates.

When considering delivery configuration the 3 phase system is sometimes considered unique and if scale as suggested in item 4 above is addressed the following may assist in those considerations. When a distributor builds a distribution system the notion that the 3 phase system is a luxury system is not consistent with the power system in Ontario. Generation is done at the 3 phase level for good and technical reasons. In Ontario, the deliveries by large generators to the transmission system are 3 phase and deliveries by the transmission system to distributors are universally or almost universally 3 phase. If a distributor delivers power to customers using 3 phases it is recognised that the metering costs and wire delivery costs are generally higher than they would be for a single phase supplied customer. The distributor typically decides whether power will be delivered from a single phase supply or a 3 phase supply. In some cases customer equipment requires a 3 phase or polyphase supply. Where the distributor requires that the customer supply be 3 phase, this is usually a scale related issue. The scale is typically captured such that once a customer's load exceeds a certain level, say 100kW or 250kW, the distributor will require a 3 phase supply. Customers taking a 3 phase supply are typically responsible for a higher cost protection scheme which responds to loss of 1 or 2 phases by isolating the supply to all 3 phase loads. At the same time once a 3 phase supply is established to a customer the distributor's issue around phase balancing on its distribution system are reduced by not having to worry about balancing the single phase lines on a feeder as it relates to the 3 phase customer. For those distributors that have a bulk or notional sub transmission system, the operation of those identified systems is consistent with the language applied to the 3 phase system above.

Time differentiated variable rates for distribution system use can be set to encourage efficient use of the distribution system and complement efficient use of the generation and transmission systems.

Diversity is simply a method of recognising that capacity may be utilised in a different time. The key concept here is that it is the time of use of the peak capacity of individual customers or classes that creates diversity and time of use rates provide a direct signal to customers without the introduction of the misunderstood concept of diversity.

Time differentiated variable rates are a better allocator of system costs than diversity allocated using class non-coincident peak demand. Non-coincident peak demand class cost allocators may give customers in a class a price signal that the class cost is indifferent to moving energy use to between 9am and 10am based on the load shape of that class. At the same time, non-coincident peak demand class cost allocators for a second class which peaks at between 9am and 10am (the class load shape) tells customers in that class to move its demand away from the 9am to 10am period. Customers from these 2 classes may be served from the same feeder, the same transformer and even the same secondary buss. The distributor serving these 2 classes may in fact have a peak demand between 9am and 10am or in fact at some other time. What this demonstrates is that the introduction of any classes combined with the use of non-coincident peak demand for cost allocation blurs the price signal to the customer and in fact can create conflicting and ambiguous if not confusing price signals in the minds of customers. It is the capital that the distributor has invested in making capacity available that drives the distributor's costs (including operating costs) and not the non-coincident peak demand of a class.

Rates are currently designed to share costs within a class once the allocation process is complete but the cost allocation process is designed to share costs between classes. The allocation between classes is a poor substitute for rates which pass distributor costs directly to customers. This is true because the only place that class cost allocation and costs come together is at the allocated capacity revenue requirement. Further, if the cost allocation produces confusion in the minds of the rate payers it can produce revenue instability for the distributor.

Time differentiating variable costs can provide a direct linkage to distribution system cost causality.

Failure to fully utilize the resource investment including capital being made in Smart Meters creates an undue waste of distributor capital and customer's payments in support of Smart Metering.

The requirement for incremental distribution system capacity is driven by the time and location that the capacity is required. Location requirements other than density would create a complex if not indefensible pricing system as the decision to build or not build capacity at a particular location is a decision made by the distributor. Time of use is an effective tool that treats all customers equitably in that the price paid is uniform.

The staff Discussion Paper on page 7 talks about cost causality, identifying coincident peak as the key driver:

> "Generally, since most distribution system designs are based on the peak demand of a group of neighbouring customers, each rate class's contribution to peak demand is used to allocate demand-related distribution costs."

This quote implies that coincident peak is used for allocating costs.

The use of Non-Coincident Peak to allocate costs between the classes is a method of identifying the diversity that exists within the class and sharing the diversity benefit between classes. If the goal is to permit the assignment of the costs associated with owning, operating and maintaining the distribution system and we are dealing with a "clean slate" as suggested on page 1 of the staff Discussion Paper, then cost causality should be examined before customer classification is established. The staff Discussion Paper indicates on page 7 that cost causality is driven by the requirement for the distributor to provide capacity:

> "Distribution assets located closer to the customer are generally designed based on the customer's peak demand or, more likely, the peak demand of a group of customers that live or do business in a certain vicinity within the distributor's service area."

It further indicates on page 24 of the staff Discussion Paper that energy (kW.h) is used as a "proxy" for demand (capacity). If a small customer (load) is only on the distributor's system from 2am to 3am each day it is unlikely that the distributor would have to build capacity to make delivery service available. If a customer has even a 2kW load coincident with the distributor's peak, then if enough of those 2kW customers are added to the system in a given location then clearly at some point the distributor would have to add additional capacity to its system to make the deliveries available. From these examples it is apparent that the time of use of capacity is important in determining the cost causality of supplying that capacity. Much confusion and argument about cost allocation stems from the need to allocate diversity between customers. This historical need stems from the lack of knowledge about customer's contribution to the requirement for peak capacity on the distribution system.

The only other consideration which materially impacts on the costs of providing delivery capacity is the load density of the distribution system and any pricing scheme should be able to recover material incremental costs of very low density or very high density on a cost causality basis.

What the unbundling of the distribution, transmission and generation systems has permitted is unbundling each of these three components to permit each one to identify its costs and recover them on a cost causality basis. There are potentially 8760 different hourly prices for energy in a non leap year. In fact, those hourly prices are passed on to end use consumers either directly or through the regulated price plan. In the absurd extreme, it might be possible to use a similar approach on distribution system costs except that neither distribution nor transmission systems are supplied on an hourly basis. They are in fact constructed to meet either a seasonal or annual peak given due consideration to ambient temperature. Simplicity may drive the rate designer to consider both a summer and winter peak when establishing the boundaries on the peak period and the commensurate leverage between peak and off peak period rates. Simplicity or understandability by the customer should be paramount in the establishment of pricing and price periods.

What drives the system needs for capacity are the times at which a peak occurs on the system. As such, it is possible to assign distribution system costs (capital and operating & maintenance) on the basis of time of use of the distribution system. If time of use were used to assign distribution system costs then the traditional nightmare of the sharing of diversity using Non-Coincident Demand (NCP) falls away and cost allocation studies are limited to the refinements associated with specific equipment or services used by customers. The specific items would include recognising the costs or savings associated with the following:

Adjustments to the Service Charge:-

5. Billing and collecting
6. Metering single phase or 3 phase
7. Secondary conductors LDC owned or customer owned

Weighting factors or specific adjustments applied to volumetric rates:-

8. Transformation LDC owned or customer owned
9. Distribution system construction – overhead vs. underground
10. Distribution system construction – 1 phase vs. 3 phase if warranted
11. Distribution system density

These utilisation specifics could be captured by way of a discount or surcharge on either the fixed customer charge or the variable charge. The current transformer ownership allowance is already treated as a discount on the variable volumetric charge. Once the revenue requirement is established, these simple adjustments would certainly be a cost effective alternative to cost allocation studies and costly load research.

If time of use distribution costs were introduced the off peak period could be determined generally by considering the time period where the demand is typically below 75% of the annual distribution system peak demand. In suggesting the 75% possible threshold, considerations would include most monthly and seasonal peak shoulder demands within the peak period without unduly restricting the off peak period. Off peak would generally include weekends and statutory holidays and the period of say 10pm to 8am for weekdays (Monday to Friday except statutory holidays). For those distributors worried about the unlikely or unusual situation where a large load utilises facilities primarily in the off peak period, an excess capacity charge could apply to dedicated or near dedicated facilities used primarily by a customer in the off peak period. Regardless, the idea that a distributor's overall load would increase by 33% (that is, increasing from 75% to 100% of annual distribution system peak demand) at 10pm caused by the action of one or even a few customers because of a distribution system rate differential is unlikely. Conservatively, the degree of leverage between the peak period and the off peak period might be set relatively small to identify any large scale unexpected elasticity. This degree of leverage can be set as a discount factor applicable to the peak period rate and used to establish the off peak period rate. As experience is gained the degree of leverage could be increased to encourage manufacturers to produce cost effective cool or heat storage devices and delay timers on such things as dishwashers, electric clothes dryers and electric water heaters. An initial degree of discount might be set as low as 11% (a discount factor of 0.9) so that the peak period distribution charge would be 11% above the off peak charge.

A residential customer with a 200 ampere service at 120 / 240 volts can establish a peak demand of about 50kW. Customers imposing capacity requirements above 50kW may be sophisticated enough to understand a change to an explicit demand charge for kW in excess of 50kW. It is necessary to establish some reasonably expected relationship between the over 50kW peak period demand charge and the kW.h charge. The peak period kW.h charge could apply to the average peak period kW.h use for customers at or about the 50KW demand level (say 9,000 peak period kW.h) with a demand charge set at (9,000/50 times the kW.h rate) or about 180 times the peak period energy rate.

Using this approach, a single customer class could be created where the first so many kW.h in the off peak period would attract a price of (0.9) times (Q) cents/kW.h and the first so many kW.h in the off peak period would attract a price of R cents/ kW.h. In addition, peak period demands in excess of the peak period demand over 50kW would attract a distribution system charge of (0.9) times (S) cents/kW in the off peak period.

If it were not for the potential concern for "free riders" the discount factor could be established so that the off peak distribution rate would be 0.0 cents/ kW.h (zero). A zero off peak distribution energy rate would certainly incent customers to shift their use of energy. This might well free up significant peak period capacity at the generation and transmission level. The impact of a zero off peak distribution charge would be to materially increase the peak period distribution charges for all customers. The degree of discount for the off peak energy rate might well be set different from the degree of discount applicable to the peak period demand rate for over 50kW.

The approach identified in the previous few paragraphs eliminates undue discrimination and cross subsidy caused by the present establishment of non-homogeneous classes and eliminates such issues as class boundary issues and customers moving between classes. Under the one class approach, adjustments to the “standard or uniform “ rates for the LDC would be based on utilisation or non-utilisation of specific attributes of the distribution system (cost causality).

Standby rates for merchant generators or embedded generators could be based on the “uniform” rates. This would encourage generators to schedule their interruptions at a time when they would have least adverse impact on both the distribution system and the transmission system.

Once the overall distribution revenue requirement is established for a distributor by the regulator, the calculation of the individual specific rates under the one class system can be readily established.

The overall distribution revenue requirement would be reduced by the expected miscellaneous revenue together with the expected revenue to be produced by the 4 groups of atypical material users identified as bullets 1 to 4 inclusive above.

The avoided cost approach could be used to establish the fixed service charges and include the minor customer specific facility adjustments identified by bullets 8 to 11 inclusive above. The expected revenue from the adjusted service charges is then deducted from the net distribution service revenue to produce the net variable service revenue which can and should be time differentiated. This net variable service revenue would have to be increased for the cost of transformer ownership allowance.

Calculation of two variable time differentiated distribution rates

The variable service revenue can be used to calculate the peak period energy rate of **Q** cents/kW.h and the variable over 50kW peak period demand charge of **S** cents/kW.

Total variable revenue requirement	= Z
***** Peak / off peak period energy discount factor	= A
***** Peak / off peak period demand discount factor	= B
***** Peak period chargeable kW.h volume **equals K** (rounded to 100 or 1000kW.h)	= C
***** Off peak period chargeable kW.h volume	= D
Peak period energy rate	= Q
Off peak period energy rate **equals (Q) x (A)**	= R
Peak period over 50kW demand rate **equals (L) x (Q)**	= S
Off peak period over 50kW excess demand rate **equals (S) x (B)**	= T
(applicable to over 50kW kilowatts in excess of the peak period kilowatts)	

The known distributor volumes would include the sum of the monthly:

peak period kW.h below **C** kW.h for each customer	= E
off peak period kW.h below **D** kW.h for each customer	= F
peak period kW in excess of 50kW for each customer	= G
off peak period kW in excess of peak period kW for each customer	= H
(applicable to over 50kW kilowatts in excess of the peak period kilowatts)	

* Information used to establish the demand charge starting at the 50kW boundary

Average monthly peak period energy use for customers at or near the 50kW demand level	= K
Hours use for the peak period demand charge **equals (K)/50**	= L

The time differentiated variable revenue can be calculated using the following equation:

$$Z = [(E) \times (Q)] + [(F) \times (R)] + [(G) \times (S)] + [(H) \times (T)]$$

Knowing **Z**,
Q can be calculated by substituting in the previous equation in terms of **Q**.

$$Z = [(E) \times (Q)] + [(F) \times (Q) \times (A)] + [(G) \times (L) \times (Q)] + [(H) \times (L) \times (Q) \times (B)]$$

Given **Q** the following monthly variable rates can be calculated:

Peak period energy rate up to **C** kW.h	= Q
Off peak period energy rate up to **D** kW.h **equals (Q) x (A)**	= R
Peak period demand rate for kW in excess of 50kW **equals (Q) x (L)**	= S
Off peak period demand rate for over 50kW kilowatts in excess of the peak period kilowatts **equals (S) x (B)**	= T

*** Indicates the item could be fixed or established on a province wide basis.**

Consideration should be given to providing similar weighting to transmission rates if the OEB wishes to further optimise the utilisation of the power system.

In the long term it may be most cost effective to establish a third time period such that the distributor might have a super peak period, a shoulder peak period, and an off peak period.

Smart Metering may encourage rate designers to think of multiple and more narrow pricing periods. If the periods become too narrow there is a risk of distributor pricing becoming unstable as rate designs chase a narrowly defined peak. If province wide peak periods are universally accepted and established there might be an advantage to making real time hourly information available to customers. This information would include commodity prices and whether distribution rates are in the peak period or off peak period available to customers. Such information could be provided in an energy box on the weather channel or some equally accessible media. Rate design is never perfect and impact of information on consumer behaviour is not always accurately predictable. Customers may respond by simply saying, “It’s been too hot for too long and I don’t care what the price is – the air conditioning is going on and I’ll put an end to the suffering.” Alternatively, customers may put up with the heat for one day a week and go to the mall for the other 4 peak period days. The inelasticity or elasticity of customer use of electricity is not well understood. Issues like relative hardship for individual customers or potential competitive disadvantage to some customers relative to other customers in similar businesses are only a few of the issues that would have to be weighed when anticipating customer response.

The staff Discussion Paper states on page 30 that

> “given the increased sophistication of many customers, a single standard of service at a single rate may be questioned.”

All customers are reliant on the electricity delivery system. The notion that there some customers requiring a higher standard of service than others is not valid. In any case, such difference in service quality cannot readily be measured by the weak quality of service parameters currently in use. It is not practical to implement pricing on a broad scale that would reflect the quality of service. Only the most sophisticated customers to understand the consequences of varying degrees of reliability and determine whether their lifestyle or business operation can tolerate a lower standard of reliability. There may be a home for this concept with customers having embedded generation and flexibility in production schedules. Such a situation could be used to reduce the cost of any standby charges associated with the embedded generation. Further, this question begs the introduction of an interruptible supply and delivery rate(s). The benefits of such a rate would seldom flow to distributors (with the exception of the embedded generators identified above) and would more likely flow to the transmission system or in fact the province wide generation supply system. In those cases, the cost and benefits would be best identified and funded directly by the transmission company and/or the Independent Electricity System Operator.