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May 30, 2008

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
2300 Yonge Street
27th Floor
Toronto, ON
M4P 1E4

Dear Ms. Walli:

Re: EB-2007-0031 – LPMA Comments on Staff Discussion Paper – Rate Design for Recovery of Electricity Distribution Costs

These are the comments made on behalf of the London Property Management Association ("LPMA") on the Staff Discussion Paper – Rate Design for Recovery of Electricity Distribution Costs dated March 31, 2008.

The comments provided below are provided based upon the headings of the relevant sections provided in the Staff Discussion Paper.

3.3 Efficiency Principle

The Staff Discussion Paper highlights a key debate in rate design – fixed versus variable charges. As stated there, rates should encourage customers to maximize the use of existing assets (static efficiency) while at the same time rates should encourage customers to use the system in ways that lead to rational growth (dynamic efficiency).

Most distributors appear to favour distribution rates that lead to the efficient use of the distribution system (static efficiency). This would mean that most if not all of the distribution revenues would be recovered through fixed charges. On the other hand, environment advocates support the rate design approach that enhances the overall efficiency of electricity consumption (dynamic efficiency). This favours a rate design system that has a high proportion of the revenue requirement recovered through variable charges.

LPMA believes that a balance approach to the efficiency principle should be followed. Neither of the extremes noted above should be followed. Rather, fixed and variable components of a rate should both be used to recover the revenue requirement. The determination of the mix of the fixed and variable charges should be based on cost causality. More comments on this issue are provided in later sections of this submission.

4.2 Options for Customer Classes

Staff has asked for comments on the appropriate role for interruptible rates, or more accurately, interruptible service.

LPMA submit that interruptible service (rates) should be offered where their use can encourage customers to maximize the use of existing assets (improve the system load factor). Interruptible service should be available to those customers that contract for such a service. These customers would generally be large customers served from the primary and/or sub-transmission facilities. These customers should be capable of being interrupted upon short notice. Interruptible service could be reflected as a rate option within other rate classes.

LPMA agrees with the concern expressed by some parties that customers using interruptible rates are rarely interrupted, resulting in few if any system benefits. As a result, the Board may want to investigate a limited availability interruptible service or services. For example, a service may be interruptible only in the peak TOU period, with another level of interruptible service available in the mid peak TOU period. There would appear to be little, if any, need for an off peak interruptible service. The Board may also want to consider the benefits associated with a seasonal peak and/or mid peak interruptible service. This could be different distributor by distributor. For example, a northern winter peaking utility may benefit from having a winter peak interruptible service while a southern summer peaking utility may benefit from having a summer peak interruptible service. However, the concept is the same. Distributors would have the ability to interrupt a well defined (and probably small) number of customers during pre-defined periods (both seasons and time of day). This would allow distributors to avoid investing in peak demand assets that would be used infrequently.

4.3.1 Connection Voltage

LPMA requests that Board Staff provide some clarification on Table 3. In particular, this table is supposed to show the average of the monthly kWh for the existing and proposed classes. However, the figure of 28.6 shown in the 50-999 kW row and secondary – single phase column appears to be the same figure shown in Table 2 which is based on average of peak kW. Table 3 seems to suggest that the average monthly kWh is less for the existing customers in the 50-999 kW class as compared to the <50 kW and the residential classes. This also appears to be what is presented in the secondary – 3 phase column, which shows that customers in both the 50-999 kW and 1000-4999 kW classes have an average of monthly kWh figures that are smaller than that for those customers currently in the <50 kW class. If these figures are not the correct kWh figures that should be shown in Table 3, what is the impact on the overall class average calculated there? If these figures are correct, an explanation would be useful.

Board Staff have asked whether a distinction for the new connection-based classes is practical and if such a classification is logical for distribution systems.

LPMA believes that a distinction of secondary – single phase and secondary – three phase as compared to primary/sub-transmission is logical for distribution systems. However, LPMA is not sure that the distinction between primary and sub-transmission is appropriate. The Staff definition of sub-transmission systems is having a 3-wire line (i.e. without an integrated neutral) while a primary system would be defined as those that have a 4-wire line. The distinction between sub-transmission and primary would be regardless of voltage. However, Staff had previously indicated that that they believed that cost causality is closely linked to connection voltage. In the example using Milton data, it is assumed that the Staff definitions have been used. In this example, there is an overlap of voltages between the sub-transmission and primary classes.

If the costs associated with a sub-transmission system as compared to a primary system (both based on the Staff definitions) are significantly different, then it would be logical to distinguish between the two. However, the costs differential is marginal, then it is questionable as to why they should be combined into one class.

As for whether or not the distinction is practical, that will depend on the ability of the distributors to provide detailed information at the level of segmentation required for the cost allocation model that would be associated with these connection-based classes. LPMA would be informed by comments from Staff and the distributors about potential problems they foresee if the new connection-based rate classes were to be adopted.

Staff has also asked for comments on the appropriate levels of division of the secondary class with 3 phase service and whether these are more appropriate as distinct classes or sub-classes.

The appropriate levels of division of the secondary class with 3 phase service, if any, depends on the magnitude of the difference in costs. LPMA does not believe the Board should consider these differences as sub-classes. The difference in costs should be reflected in different classes, not the addition of sub-classes.

However, LPMA is concerned that the volume usage as suggested by Board Staff is likely to create boundary issues going forward. Rather than using a discrete step function to deal with this issue, if it is relevant, the Board should investigate a continuous function based on volume usage. Such an approach would eliminate the problems associated with boundary issues.

4.3.2 Proxies for Voltage

If not the connection voltage, LPMA believes the next best approximation should be determined on a case by case basis. However, LPMA notes that the problem described in the Staff Discussion Paper may be limited to a small number of distributors. This should not mean that the Board should avoid basing classes on the engineering distinctions of sub-transmission, primary and secondary systems for the majority of distributors. Further there may not be one best approximation that could or should be used for the remaining distributors. These distributors may have to be reviewed on case by case basis to determine an appropriate approximation. This is because of the potential for different system designs making it difficult if not impossible to separate customers into the classes using a common set of criteria.

5.2.1 Price Signals in the Rate-setting Context

LPMA believes that there is a connection between variable rates and long run variable costs. This is because customers do respond to variable rates. Variable charges are an effective way to control long run variable costs in the rate setting context.

If customers do not have a price signal that using more will result in higher rates, they will not have any incentive to mange or control their use. The variable rate will show the customer the impact of a change in use. This is not say that customers will react immediately. In fact, they will take time to adapt, which is consistent with the notion of the long term. Customers are not likely to replace equipment well before the end of its useful life to just save a little on their electricity bill. However, they are more likely to replace the equipment sooner than they otherwise would. In other words, a variable rate will influence a customers use (and thereby influence long run variable costs) in the long run. Variable rates are unlikely to have a significant impact in the short run. However, having variable rates in the short run is required if they are to have a longer run impact.

It should be noted that if customers do not respond to variable rates for the commodity, then the province and its electricity distributors will have spent a lot of money and will accomplish nothing. There is not reason to believe that this is true. If variable rates for the commodity are expected to have an impact in the long run, then there is no reason to believe that variable rates on the distribution side will have no impact in the long run.

5.3 Revenue Stability

LPMA first and foremost notes that if the Board adopts any revenue stability mechanism, including the use of a high fixed charge and low variable rates (in relation to the allocated costs), then this reduction in risk associated with volume and demand deviations related to weather and/or growth an/or economic conditions will substantially reduce the business risk of the distributors. This would need to be reflected in a reduced return on equity and/or equity component of the capital structure.

LPMA believes that a properly balanced combination of a fixed charge and a variable charge based on demand should provide a distributor with revenue stability. This balanced combination should be based on the cost allocation results for the distributor.

The main problem that LPMA sees with the RSAM approach (any other similar approaches) is that it can send the wrong signal to customers. A warmer than normal summer would result in higher demand and higher energy consumption than forecast in a summer peaking distributor. This would likely result in higher energy costs than forecast, resulting in future costs to be recovered from customers. On the distribution side however, the additional revenue that would be generated would need to be credited back to customers in the future. This would be counter intuitive. Higher demand and energy consumption would result in higher commodity prices, but lower distribution rates! Similarly if consumption and demand were lower than forecast, distribution rates would go up. This would be very hard to explain to consumers. On one hand they are being encouraged to reduce demand so that future costs can be minimized and on the other hand when their demand does go down, their rates go up.

6.4 Design of a Variable Charge Based on Demand

LPMA agrees that it would be preferable to implement a demand charge methodology that provides a price signal to customers to limit their demand during all of the hours of year that are defined as peak hours, using the same definition as used for the TOU periods.

Customers will have access to their daily and hourly consumption data from the smart meters. In order for the variable charged based on demand to have an impact on customer behaviour, it needs to be relevant to the customers' future consumption and not entirely based on their past consumption. LPMA believes that the billing determinant to be used each month should be the customers' average peak demand for the month. This average would be the average of the highest hourly consumption during the peak period in each day in the month that has a peak period (i.e. it would exclude weekends and holidays). Thus, if a customer had a relatively high peak demand on any day, they can still impact on their bill by reducing their peak demand on the remaining days of the month.

This methodology would be easily understood by the customer; it would provide a level of stability in the demand billing determinant that would be of importance to the distributors who need revenue stability; it would provide ongoing incentive to customers to minimize their peak consumption even after posting a large figure in any given day or days.

6.5 Design of a Time of Use Distribution Rate with a Consumption Determinant

LPMA opposes a time of use (TOU) energy charge as a proxy for a demand charge. This approach would provide a proxy for demand which is no longer needed. Demand will be known from the information gathered through the mart meters. Continuing to relay on an energy charge would not eliminate the problem of cross subsidization between different load factor customers within a rate classification. Demand data will be available and should be utilized.

6.6 Single Phase Secondary Customer Rate Changes

Distribution customers should pay rates that are more reflective of the costs they cause due to load factor difference based on each distributor's cost allocation study. In the view of the LPMA, this is the goal of the rate redesign. Smart meter data will provide a much better indication of which customers are driving costs. In order to impact on these customers, rates must be more reflective of the costs they cause. How else can customers be expected to change their behaviour over the long run in order to impact on long run costs? Two customers that have the same peak demand cause the same level of costs (capacity) to be incurred by the utility. If one of those customers consumes half the energy of the other, any cost recovery through an energy charge (as in the current case for small volume customers) means that the low load factor customers pays considerably less for distribution service, even though they drive the same amount of costs as the customer with a high load factor. With data from smart meters this inequity can be eliminated or at least reduced by the introduction of some type of demand charge.

The revenue to cost ratio for the new Single Phase Secondary Class should not be constrained in any way by the prior revenue to cost ratios of the existing Residential and GS classes. The Board may, however, deem it appropriate to phase-in the movement from the current revenue to cost ratios to those required for the new class over a number of years. This would help reduce any rate shock to groups of customers that may be significantly and negatively impacted by the change. LPMA notes that in a number of 2008 COS decisions the Board is requiring that rates for street lighting be adjusted over a three year period to move them from existing low levels to at least a 70% revenue to cost ratio.

6.7 Residential Sub-Class

LPMA believes that it is sufficient to maintain a residential sub-class as a means of identifying residential customers for purpose of billing treatment that is available only to residential customers under current legislation. It is not clear what other action or designation might be required.

8.2 Contract Capacity and Demand Based Rates

LPMA believes that the most appropriate option is based on contract demands. Each primary customer would have a contracted maximum firm demand. This would represent the maximum demand that the utility was obligated to provide to the customer. A capacity charge equal to the capacity related costs allocated to this class divided by the sum of the contracted firm demands would be appropriate. Many of these customers may also be natural gas customers that receive distribution service under contracts that have a similar firm demand charge (in addition to monthly customer charges and a variable per cubic meter charge).

It should be noted that this approach also enables distributors to provide an add-on interruptible service. That is, interruptible service would be available on top of the firm contracted peak demand if available. Again, this is similar to the services available to the customers from natural gas distributors.

LPMA does not believe that a demand charge based on the actual monthly peak demand rather than the contracted demand is appropriate. This is because the system will be designed to the contracted demand for each customer. In a simple situation, consider the example where there are two primary class customers, each with the same contracted demand. One of the customers has a higher load factor than the other. If the demand charge is based on the actual monthly peak demand, the higher load factor customer will pay more than the lower load factor customer, despite the fact that the capacity required for both customers is the same. This is precisely the situation that should be avoided wherever possible.

9. Rate Design for the Sub-transmission Class

LPMA sees no reason why the same rate design as that for the primary class could not be used for the sub-transmission class.

10. Rate Design for Embedded Distributors

LPMA believes that a separate class for embedded distributors should be maintained. As the Staff Discussion Paper indicates, these customers can be rather unique. The annual load of an embedded distributor can be similar to a large customer served under a primary or sub-transmission class, but the load profile can be more reflective of customers served under the secondary rate class. Embedded distributors, therefore, are sufficiently different from the other proposed rate classes and should have their own rate class.

The Board has experience with embedded distributor rates in the natural gas sector, especially within Union Gas. Union Gas serves a number of embedded natural gas distributors ranging in size from those that service a handful of residential customers (less than 100) to Kitchener Utilities that has approximately 60,000 residential, commercial and industrial customers. In fact, Union Gas has two separate sets of rates to serve these customers. One is used for the smaller utilities while the second set of rates serves the three larger distributors. Under this second set of rates, there is a combination of a customer charge, a demand charge and a variable per cubic meter charge. The demand charge is based on a contracted demand level between Union and the distributor. Costs are recovered based on these contracted demands that determine the capacity Union need to reserve to serve these customers. These contract demand levels can be changed on an annual basis to reflect growth in the embedded distributor, as well as loss of major customers and the impact of conservation. It should be noted that the contract demand is based on a peak day scenario, not normal weather, to ensure that the host distributor has the capacity to serve the embedded distributor under such a situation.

LPMA believes that a similar approach should be adopted for embedded electricity distributors.

Staff have invited comments as to the appropriateness of these options for designing the rate for this class if a separate Embedded Distributor Class is adopted.

LPMA believes that the rate design should follow the same basic approach as that for the Primary and Sub-transmission classes. That is, there should be a monthly fixed charge and a contract demand based capacity rate. Both of these rates would be based on the allocated costs.

Time-of-Use based charges should not be used, at least at this time. Embedded distributors have little if any control over its peak demands. The Staff Discussion Paper states that such rates would provide a measure of protection to the host distributor. LPMA disagrees. The peak demand of the embedded distributor can vary widely based on weather and industrial shutdowns. In other words, there could be substantial unpredictable changes in the peak demand from month to month. A capacity charge based on a fixed contracted demand would provide more protection to the host distributor since it would know the capacity revenue that would be generated based on the contract with the embedded distributor. This does preclude the embedded distributor from working with its customers to manage its system peak demand. If it is able to do so, this would be reflected in the following year or years contracted demand level which could be reduced or would grow less slowly.

11. Rate Design for Load Displacement Generation

The following comments relate to load displacement generation that are limited to generation facilities that supply electricity to a specific load, displacing electricity supply that would otherwise be obtained from the local distribution system and are in excess of 500 kW.

LPMA believes that rates for customers that have load displacement generation should not be any different than for customers without load displacement generation. All customers should pay for the costs that they create.

For large customers served under a primary or sub-transmission class, LPMA believes that rates should included a monthly fixed charge to recover the allocated fixed costs and a contract demand based capacity charge. This same design should apply to customers that do and do not have load displacement generation. It would be up to the customer to determine if they want to contract for the full capacity they require in the event their generation fails. This capacity could be firm or a combination of firm and interruptible. If the generation failed during a peak period when the distributor was at or near capacity, the customer would be required to limit their use to their firm demand level. If the generation failed during a peak period when the distributor still had some excess capacity, the customer could utilize at least some of their interruptible capacity. If the customer decided to contract for firm capacity less than their total requirements with no load displacement generation, then they would be required to operate within those parameters. Any excess capacity used over their firm contract demand would be a significant penalty rates.

The key issue is that the customer should be expected to pay for the capacity that they want reserved for them, just as would any customer served under a primary or sub-transmission class.

The same analysis applies to those customers that may have load displacement generation, but are served through a secondary class. In this case, however, there is more of an issue because there is no contract demand that can be used for billing and capacity purposes. Such a customer would not pay for the excess or standby capacity built into the system in case of generation failure unless then actually consumer addition power when the generation was unavailable. This would be reflected through a higher variable charge based on actual demand.

Distributors are likely to complain that this leaves them with excess capacity that they may not get paid for if the customer does not experience a generation problem. However, this may not be necessarily accurate. When determining an appropriate capacity charge for the rate class, the cost related to the excess capacity would be included in the costs. The units over which this cost would be recovered may not include any use of this capacity by the customer as the utility would not forecast any unscheduled outages. This would mean, however, that other customers would be paying a higher demand (capacity) charge than they otherwise would. However, the load displacement generation may provide these other customers with other benefits, such as reduced line losses and reduced peak generation commodity costs.

In conclusion if the load displacement generation customer is not in the primary or sub-transmission class, the Board may want to establish a separate secondary class for these customers so that any excess capacity held for them is paid for by those customers and not by the other customers in the secondary class.

LPMA does not believe it is advisable to assume the targeted end-state diversity in setting rates in order to stimulate projects. There are many other factors that will determine the actual end-state diversity. New technologies may make load displacement generation more economic over time. As such, the end-state may not be static but dynamic, changing over time. Rates should reflect current costs. If these costs change over time as more load displacement generation comes onto the system, then the rates should change to reflect these changes.

12. Rate Design for Unmetered Scattered Load

LPMA believes a separate unmetered scattered load class should be mandatory. Further there does not appear to be any need for separate classes for street lighting and sentinel lighting. However, there may be a need for separate classes for other reasons. Lighting load generally occurs in the off peak period, perhaps with some in the mid peak period as well. If there are some unmetered scattered loads that also use power during the peak period, then it could be argued that based on cost causality a separate class and allocation of costs should be done for those applications.

13. Rate Design for Metered Scattered Load

The Board has dealt extensively with this issue in the natural gas industry in the 1970's and 1980's. The OEB allows the inclusion of a term relating to group billing in the general service rate schedule in its E.B.R.O. 309 – II Reasons for Decisions (October 31, 1975). This term provided for the combining of meter readings for billing purposes for "boards of education, for public buildings covered by franchise agreement and in cases where meters are located on a contiguous owned piece of property not divided by a public right-of-way". The OEB considered that the limited use of combined billing to be reasonable but it also indicated that it would object to the extension of this policy.

The following is the section of the general service rate schedule resulting from E.B.R.O. 309-II that dealt with this topic:

<u>Supplemental Service To Customers Under Group Meters</u>
Combination of readings from several meters may be done at the Company's sole discretion for Boards of Education, for public buildings covered by franchise agreement and in cases where meters are located on a contiguous owned piece of property not divided by a public right-of-way. In such cases an additional service charge shall be rendered each month in the amount of $2.00 for each such meter so combined.

In it's Reasons for Decision in E.B.R.O. 371-II (December 31, 1980), the OEB said that it viewed group billing as inherently discriminatory. The OEB directed that group billing for residential customers be discontinued. The Board further directed Union to consider combining Rate M1 (residential service rate) and Rate M2 (general service rate).

In response to this directive, Union Gas proposed that Rate schedules M1 and M2 be merged into one schedule to be known as "General Service Rate Schedule M2". The Board approved the merging of these two rates into one in its Reasons for Decisions in E.B.R.O. 380 (September 14, 1981). In that Decision the Board noted that Union Gas had allowed the consumption through two or more meters to bed added and billed as a single customer. Union proposed that this practice continue under the new M2 rate schedule.

The Board noted that the customers to whom the group billing arrangement had been extended fell into two categories. The first was industrial and commercial customers with a single specific location with meters on contiguous properties where there is a single owner and the property is not "divided" by a public thorough-fare. The second category was customers in the public sector and in this case involved the combining of consumption from meters at different locations where properties were not contiguous. This concession had been extended to municipalities in return for franchise agreements. In addition, group billing was used as an incentive to school boards to change to natural gas in the early 1970's.

The OEB stated that it was of the opinion that any service which was at the sole discretion of Union and effectively offers a rate reduction to selected customers in a class may be unduly discriminatory. The Board also realized, however, that in certain situations supOply through more than one meter for a large customer at a single location may be economically advantageous to the utility. As a result, the Board directed Union to bring forward a proposal for the termination, or in any event, severe restriction of the group billing arrangement under Rate M2.

At its next main rates case (E.B.R.O. 382) Union made it clear in its evidence that it was in favour of group billing and that should be continued in a manner similar to existing practices. In its Reasons for Decisions (April 8, 2982) the OEB concluded that the customers utilizing group billing could be divided into three groups: school boards, municipalities, and commercial and industrial customers.

It was argued by an intervenor that group billing for single locations was justifiable on technical, economic as well as marketing considerations and also pointed out that the installation of one larger meter capable of measuring large volumes of gas posed a further problem given that such meters were unable to accurately measure small amounts of gas which could result in an increase in unaccounted-for gas (gas losses).

In its Decision, the OEB ordered that effective April 1, 2983, group billing for municipalities and school boards on non-continuous properties was to be removed from the M2 rate schedule and any term of any franchise agreements under which Union provided group billing was thereby superseded. The Board further found that for any one customer having facilities on one or more contiguous pieces of property and being served through more than one meter, that those meters should be combined for billing purposes. The Board felt that to do otherwise would effectively place large capital expenditures upon a customer or up Union to revamp the gas distribution system. In addition, the Board felt that the conversion of such a complex to a single meter could increase unaccounted-for gas.

The following is the section of the general service rate schedules as the currently exist at Union Gas:

Supplemental Service to Commercial and Industrial Customers Under Group Meters
Combination of readings from several meters may be authorized by the Company and the Company will not reasonably withhold authorization in cases where meters are located on contiguous pieces of property of the same owner not divided by a public right-of-way. In such cases, an additional service charge shall be rendered each month in the amount of $15.00 per month for each additional meter so combined.

LPMA submits that parties should take this evolution in the natural gas industry into account when it considers rate design for metered scattered load.

It should be noted that the benefit to natural gas customers using this supplement service is derived from the fact that distribution rates for natural service for general service customers are on a declining block basis. In other words, incremental monthly consumption attracts lower rates. Combining meter readings into one account allows consumption to be aggregated and move more consumption into lower priced blocks. There is also a small reduction in the net impact from the monthly customer charge (currently $17 per month) being offset by the additional service charge of $15.00.

14. Revenue Recovery of Distribution System Losses

Cost causation would support the approach that if distribution system loses are higher in the peak period than in the mid peak period, which in turn are higher than in the off peak period, then these costs should recovered over the commodity in the respective periods. This may mean the creation of three loss factors in place of the one used now.

LPMA believes that this approach may cause additional customer confusion related to losses, but believes it would reinforce the need to reduce peak demands on the system.

Please contact me if the Board requires any further information related to these comments.

Sincerely,

Randy Aiken

Randy Aiken
Aiken & Associates