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

Dear Ms. Walli,

RE: EB-2015-0043 – Comments of London Property Management Association on Staff Report to the Board

A. INTRODUCTION

The following are the comments of the London Property Management Association ("LPMA") with respect to the Staff Report to the Board – Rate Design for Commercial and Industrial Electricity Customers – Rates to Support an Evolving Energy Sector dated February 21, 2019 ("Staff Report").

In Appendix A to the February 21, 2019 cover letter, the Ontario Energy Board ("OEB") provided a number of specific consultation questions, which Staff created in order to gain additional information on specific issues. LPMA has provided responses to these questions in Part C below. General comments are provided in Part B below.

B. GENERAL COMMENTS

LPMA supports the implementation of a separate rate class for small commercial customers. Whether the class boundary should be 10 kW or some other level is discussed in Section C below.

Based on the analysis of the data provided by a number of distributors and as provided in the Staff Report, it is clear that small commercial customers are more like residential customers than they are like larger commercial customers. Their demand on the distribution system is similar to residential customers (and based on data in the Staff Report is actually lower than residential customers) and their monthly consumption is also similar to that of residential customers. Commercial customers that would be in the GS 10-50 kW class have a significantly higher average maximum demand and average monthly consumption (Staff Report, Appendix A, page 4).

Given the similarity between the residential customer class and the proposed small commercial class, LPMA believes that they should be treated in a similar manner when it comes to rate design and the recovery of costs.

LPMA also notes that, similar to residential customers, the ability for these small commercial customers to shift peak load to off peak times is limited, and in most cases not economical given the level of consumption and demand. Like residential customers, small commercial customers have the best ability to reduce their electricity costs through reductions in consumption rather than in reductions in, or shifting of, demand.

LPMA does have concerns with respect to how the kW demand is calculated. This affects not only the class boundary between the two new proposed rate classes that would replace the current GS<50 kW class, but would also impact the kW billing units for the GS 10-50 kW class.

Staff has proposed that the tariff sheets for determining which customers are in the GS<10 kW and GS 10-50 kW classes would be based on the average of the highest hourly consumption in one billing month in calendar year and the highest hourly consumption in the two months on either side of the that peak month. LPMA supports the adoption of this boundary, but only on an interim basis. Once the OEB and distributors have several years of experience with the potential for customers to move back and forth between the two new GS rate classes, the OEB may want to review whether the boundary conditions should be modified or approved on a permanent basis.

It appears to LPMA that in the Staff Report, the figure used for billing purposes for the GS 10-50 kW class would be the one-hour maximum peak demand in the month. In other words, this would be a non-coincident peak that could occur at anytime of the day. LPMA believes that this should be changed to reflect cost causality.

As the OEB is aware, the most significant cost drivers for electricity distribution systems are the number of customers and peak demand. Peak demand is the coincident peak demand on the distribution system. This peak demand is what the distributors plan to meet with their assets.

The Staff proposal to use the one-hour maximum peak demand in the month means that two customers, with the same one-hour maximum peak demand would pay the same amount in distribution rates. However, one of the customers could have its one-hour maximum peak demand on the coincident peak, while another could have its peak demand in the off-peak period. The costs to serve the first customer is higher than the cost to serve the second customer because the first customer is responsible for a larger share of the peak demand costs than is the second customer. The second customer ends up subsidizing the first customer.

In addition, the Staff proposal would result in less incentive for a customer to reduce their peak consumption from the on-peak period to the mid or off-peak periods. Please note that all references in this submission to on-peak, mid-peak and off-peak periods are in reference to time of use rates.

Consider a customer that has a peak demand in the on-peak period of 25 kW. While they are able to shift this peak demand to the off-peak period through some modifications to their operations, there would be no incentive to do so. They would still be billed based on their peak demand of 25 kW. While they have reduced the costs to the distribution system by reducing their peak demand in the on-peak period, they do not receive any of these benefits.

As noted above, distribution investments are largely driven by peak demand on the distribution system because assets must be built and placed into service to handle the peak demand.

The principle of cost causality would require that costs driven by peak demand should be recovered from those customers that are creating the peak demand, in proportion to their contribution to the peak. In LPMA's view, this means that the kW billing determinant should be based on the coincident peak rather than a customer specific peak that could occur at any time of day, including in mid-peak and off-peak periods. Such a rate design would incent customers to reduce their coincident peak, reducing their distribution costs and providing distributors with potential cost reductions, especially in the long run.

While LPMA supports the use of the coincident peak as the best indicator of cost causality, there are practical problems with using a coincident peak defined as the maximum one-hour demand on the distribution system each month. The obvious problem is that no one knows when the coincident peak for the month will occur. Nor does anyone know if the coincident peak has already occurred during a month or whether it will occur later in the month.

Customers will not know when the coincident peak for a month was until they receive their bill, which is usually several weeks or more after the end of the month being billed. If a customer tries to reduce his demand during what he thinks may be a coincident peak, he is essentially undertaking a crapshoot. Customers will invariably come to the conclusion that they have no control over their coincident peak demand if it is defined as a one-hour maximum for the distributor.

LPMA believes that there are two possible ways around this problem. The first is to use the maximum of the average daily demands over the on-peak period in a billing month. For example, the average daily demands for a customer during the summer time of use rate period would be calculated over the 11 a.m. to 5 p.m. period for each non-holiday weekday. The billing determinant used for the billing month would be highest of these figures and would represent a proxy for the coincident peak.

While this approach would provide a proxy for the coincident peak, it may not be an accurate proxy for all customers. While some customers may have demand that is relatively flat over the on-peak hours each day, it is likely that other customers may have a spikier demand during the on-peak hours. For the customers with the relatively flat demand, the average would be a good proxy for the coincident peak, while for the customers with the spikier demand in the on-peak period, the average would be a poor proxy for the coincident peak.

The second approach would be to use the maximum one-hour peak demand in the billing month as proposed by Staff, but limit the peak to be in the on-peak period. LPMA believes that this would be a much more accurate proxy for the coincident peak and would eliminate the problems with the Staff recommendation of the one-hour peak in the entire billing month noted above and it would also eliminate the problem associated with the use of the maximum of the average on-peak demands noted above.

By using the maximum one-hour peak demand during the on-peak time of use period, customers now have control of this billing determinant since their use in within their control and is independent of the distributor coincident peak, over which the customer has no control or knowledge. Unlike the Staff proposal, it also provides an incentive to move demand from the on-peak period to the mid or off-peak periods.

While not being linked to cost causality as closely as with the use of the coincident peak would be, the use of the maximum one-hour peak demand during the on-peak time of use period has the added benefit of customers more likely to shift and/or reduce the peak demand because it is much more in their control than is the distribution coincident peak approach.

C. SPECIFIC CONSULTATION QUESTIONS

1. Regarding the recommendation for a new sub-class of small commercial customers, what is the appropriate definition of the class boundary and whether it would substantially change the customers who are included in the class. Options could include 10kW, 2000kWh per month, or a combination of current and voltage. (ref C.4)

LPMA supports the recommendation for a new sub-class of small commercial customers. As for what is an appropriate definition of the class boundary, LPMA notes that there appears to be two components of any potential definition.

The first component of the definition of the class boundary is whether it should be based on demand (kW), energy consumed (kWh) or some other factor (such as current and voltage). LPMA believes that the appropriate measure is demand. This is because the current customers are already in a rate class that is defined by kW (i.e. GS<50 kW). Any change to a different parameter to define the rate class such as energy consumed would be difficult to explain to customers.

LPMA further submits that demand is the best proxy of the fixed distribution cost to serve small commercial customers. Distribution costs do not generally change as a result of changes in energy consumption. If customers are going to be charged the same fixed charge in this rate class, then the distribution costs to serve them should be similar. The intent to help customers understand the fixed nature of the costs and assets to serve them needs to be aligned with what is behind the fixed costs and assets. These costs and assets are not closely related to energy consumption and are more aligned with demand capacity requirements.

The second component of the definition of the class boundary is what is the appropriate level of demand (kW) that should be used. Staff has proposed a level of 10 kW.

LPMA does not have information as to how many customers would be included in the rate class if the figure of 10 kW was changed to 15 kW, 20 kW or 25 kW. Based on the analysis in the Staff Report at pages 19-20, using the data from a limited number of distributors shows that the average maximum monthly demand for the customers in the proposed GS<10 kW rate class is lower than the corresponding figure for residential customers (3.9 kW vs. 5.3 kW) by about 25%. Increasing the 10kW figure proposed by Staff to a higher level would appear to bring the average maximum monthly demand for the small commercial customers more in line with that of residential customers.

LPMA notes that based on the information provided by five distributors in Appendix A to the Staff Report, about 75% of the GS<50 kW customers would reside in the proposed GS<10 kW class. By distributor, this percentage ranges from about 70% to 80%.

LPMA suggests that Staff should investigate increasing the class boundary above 10kW to a figure that results in an average maximum monthly demand for small commercial customers more in line with those of residential customers. There does not appear to be any reason to limit small commercial customers to those that are, on average, smaller than residential customers when it comes to demand and capacity requirements.

2. What would be the appropriate time frame for implementation and rate mitigation for the new small volume commercial sub-class? Should the OEB keep to its general policy of keeping increases under 10% per year on total bill? What considerations should the OEB examine in order to finalize the proposed mitigation? (ref. C.4)

LPMA supports the mitigation of customer impacts of the change in the recovery of costs from the current GS<50 kw rate to the proposed new rate for small commercial customers. As is usually the case, it is the low volume customers that will experience the greatest cost increases.

The OEB implemented its residential rate design policy over four years to provide customers with the opportunity to make changes in the way that they consumed. However, it was the residential consumers with the lowest consumption that were hit with the largest increases and their ability to cut their consumption was less than the larger consuming customers who were, in general, benefiting from the change in rate design.

The same will be true for small commercial customers. Those hit with the biggest increases are those with the lowest consumption and the least ability to reduce their consumption further in order to reduce their overall bill.

LPMA submits that the four-year period that the OEB used for residential customers should be the floor of any time frame for the implementation of the new small volume commercial rate class. LPMA notes that Staff has recommended a five-year time frame.

LPMA believes that a rate mitigation strategy similar to that used by the OEB for residential customers should be used for small commercial customers, with the exception of moving from a four-year implementation period to a minimum of a five-year implementation period.

In addition to the above, LPMA submits that the monthly increase should be kept to a set dollar figure per month. The dollar figure used for residential customers was $5 per month. Given that the average maximum monthly demand for small commercial customers appears to be less than that of residential customers, while their energy consumption appears to be a little more than that of residential customers, LPMA believes that the dollar figure could be a little more than the $5 used for residential customers, but should be at most $10 per month.

3. Are most current electricity distributor customer information systems capable of maintaining both a kWh and kWh/h distribution rates as part of the applied tariff? (ref. C.5)

LPMA is unable to comment on this question. Before proceeding with the small commercial rate class, the OEB should require all electricity distributors to report on the ability of their customer information systems to maintain the required information and if the current systems are not able to maintain this information, what is the estimated cost of upgrading the systems to include this capability.

4. Given that there would be bill increases for a small segment of each new class, what would be the appropriate time frame for implementation and rate mitigation? (ref. C.6)

Please see the response to Question 2 above.

One of the implementation issues identified in section C.6 of the Staff Report is the cost allocation studies currently being used. Staff is recommending that the proposed changes in the GS<50 kW class take place without changes to the cost allocation studies currently in use.

LPMA agrees that over an IRM period, there should not be any attempt to update cost allocation studies to incorporate the split of the GS<50 kW class into the two new proposed rates classes. Cost allocation studies should only be updated as part of a rebasing application for a cost of service test year.

LPMA submits that the two new classes should be treated as separate rate classes and not subclasses at the time a distributor rebases and updates their cost allocation study. This update would include updated load profiles for all customers, including the two new classes.

5. Stakeholders are invited to comment on the feasibility of implementing the Capacity Reserve Charge approach and expected consequences on customer investments in distributed generation. (ref. D.4)

Distributed generation can provide benefits to distributors other than reducing peak load. However, since the distributors do not control when the distributed generation is active, they cannot count on receiving these benefits, including peak load reduction, when they are needed.

LPMA supports the concept of a capacity reserve charge to ensure that costs are being paid for by the customers that require the capacity reserve. If these customers do not pay for this reserve, the cost of the reserve capacity is allocated to all customers on the system through the cost allocation exercise regardless of what rate class they are in. This results in an unfair allocation of peak demand costs.

Staff have proposed that GS≥50 kW customers would only have access to a full emergency backup service and that the monthly cost would be equal to the faceplate capacity times the demand rate for the rate class times a capacity factor. The capacity factor would be specific to the generation technology used. LPMA is not making any submissions with respect to the specific capacity factors shown in Table 6 of the Staff Report.

LPMA does not see any significant issues with respect to the feasibility of implementing the capacity reserve charge approach other than the determination of the appropriate capacity factors for each type of installation and others that may evolve in the future (for example, a combination of bioenergy and wind with storage, etc.).

A potentially simpler approach would be to have a contracted maximum peak demand with each customer that has generation installed behind their meter. The demand charge would be based on this contracted amount and the distribution system would be designed to accommodate this peak. This would ensure that the customer pays for their fair share of the peak capacity on the system. If the customer were to exceed their maximum contracted peak for any reason, including generation failure, a penalty charge would be added onto the monthly bill, and/or the contracted maximum peak would be ratcheted up. The penalty would have to be significant enough to incent customers to avoid exceeding their maximum peak contracted amount.

One potential drawback with this approach is that if there are a large number of customers that have installed generation behind the meter, the contract administration could become an issue. However, it is not expected that any one distributor would have a significant number of customers that would be subject to this contract administration.

With respect to the expected consequences on customer investments in distributed generation, LPMA believes that any approach – including the capacity reserve charge – that ensures that customers pay for any reserve capacity that they need and that the costs associated with this reserve capacity is not allocated to other rate classes or customers should make the investment decision by the customer simpler.

There would be no distribution savings to speak of associated with the investment in distributed generation for the customer. The savings to the customer would be solely dependent on the commodity savings and any other factors specific to the customer.

6. Should there only be one option address the issue of customers who do not abide by their maintenance or bypass obligations? Should the customer have the option? Should the distributor have the option? (ref. D.7)

Given the customer focus of the OEB, LPMA submits that the customer should have the option of what happens if they do not abide by their maintenance or bypass obligations. However, this choice should be made as part of the contract between the customer and distributor. If the customer choses financial penalties, then the penalties should be known in advance. Similarly, a customer should have the option of asking the distributor to install a load limiter at their service to ensure that it cannot take more than the agreed upon amount.

While LPMA supports the customer having the option, this option needs to consider any physical limitations facing the distributor. For example, if a distributor does not have the capacity to supply the proposed amount, then there may be a need to install a load limiter that corresponds to the distributor capacity rather than to the customers requested capacity until the additional capacity can be provided.

Yours very truly,

Randy Aiken

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