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May 27, 2016

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 - London Property Management Association Comments on Staff Discussion Paper

Please find attached the comments of the London Property Management Association on the Staff Discussion Paper in this matter.

Yours very truly,

Randy Aiken

Randy Aiken
Aiken & Associates

STAFF DISCUSSION PAPER
RATE DESIGN FOR COMMERCIAL AND INDUSTRIAL ELECTRICITY CUSTOMERS: ALIGNING THE INTERESTS OF CUSTOMERS AND DISTRIBUTORS

On May 28, 2015, the Ontario Energy Board ("Board") described a process to identify a new distribution rate design for commercial and industrial electricity customers. This followed the release of a new distribution rate design for residential electricity customers.

These are the comments of the London Property Management Association ("LPMA") with respect to the Staff Discussion Paper dated March 31, 2016. Since LPMA members are served by the GS < 50 kW and GS > 50 kW classes (in addition to residential rates) and are not customers of intermediate or large use rate classes, LPMA's comments are generally restricted to the GS rate design options presented.

B. ALIGNING THE INTERESTS OF CUSTOMERS AND DISTRIBUTORS

Staff welcomes comments by stakeholders as to what measure should be used to set the fixed charge for each class (the Monthly Service Charge) - page 8

LPMA believes that the current approach of using the minimum system with the peak load carrying capacity adjustment as the basis for the monthly customer service charge remains appropriate. This approach provides a good estimate of the fixed costs that need to be recovered from customers, separate from capacity related costs. As such, it is a good proxy for cost causation purposes. This approach ensures that customers within any rate class pay the same fixed costs regardless of their capacity requirements.

Staff invites comments on how any of the options will be affected by large amounts of net metering - page 12

LPMA believes that large amounts of net metering will have the largest impact on demand rates and rates based on kWh's, while having the lowest impact on the monthly service charge.

The impact of large amounts of net metering will depend on the level of the demand charges and vice versa. The defining impact would be based on the reliability or availability of the generation behind the meter, along with any storage capability. In other words, net metering is likely to reduce the need for capacity on the grid at any given time, but may not eliminate the need for this capacity.

However, the impact on the monthly service charge could well be all or nothing. In other words, the fixed costs recovered from a customer would not change with net metering, until the customer reaches the point where they may no longer need to be connected to the grid. LPMA notes that in many areas in North America this is already happening. Customers are faced with the same issues as is the provincial grid....that is, matching demand with supply. With generation behind the meter, commercial and industrial customers have the ability to ramp up or scale down generation to match their demands. This generation is not all solar or wind, which is based on circumstances beyond the control of the customer. Generation controlled by the customer includes that fuelled by natural gas (including renewable natural gas) and other fossil fuels. Natural gas generation is no longer only for large customers. Use of micro turbine generators are becoming more common.

More importantly, the developments and reduction in storage costs, whether battery or fuel cells or some other technology, combined with self generation will enable more and more customers to re-evaluate their need to remain connected to the grid.

C. GENERAL SERVICE UNDER 50 kW OF DEMAND

Stakeholders are invited to comment on this issue (demand based rates for smaller volume customers) - page 17

LPMA believes that demand based rates for the GS < 50 kW class of customers should be considered. Some of the design options are close to demand based rates (TOU option and energy use blocks), however none represent a pure demand based approach that would more closely reflect cost causality (capacity).

LPMA believes that the Board should consider implementing some pilot projects for a demand based GS < 50 kW rate design. This would provide data for comparison purposes with other GS < 50 kW rate design in terms of the impact on customer behaviour and costs, but could also provide valuable information that could be used to assess the potential for expanding the same rate design to residential customers.

GS < 50 kW Options

LPMA does not support either option 1 or 4. Option 1 does not provide a true understanding of the value of distributor assets that are being paid for. Not all of the costs are fixed, but this option implies that this is the case. Peak capacity is given no value whatsoever. While this approach may be fine for the residential class, given the homogeneity with that class, it is not appropriate for the GS < 50 kW class. This class contains a multitude of use profiles depending on the industry and have a wide variation of capacity requirements, unlike residential customers. This option would also reduce the cost incentive to reduce overall consumption.

Similarly Option 4 would result in winners and losers based on industries served. It also has the possibility that if the minimum charge is set too low, the customers that qualify for the minimum charge would not be paying their share of the fixed costs. LPMA notes that the Staff paper says that this eligibility for the minimum bill would be based on demand, not on consumption. This does not seem consistent with the decision not to look at demand based rates for this class at this time. If this threshold is based on consumption, then there is the potential for even stranger results. A customer could have a high demand during short periods, resulting in them qualifying for the minimum bill despite their contribution to significant capacity costs, which they would not end up paying for.

LPMA supports Option 2. Time of use distribution rates have two significant advantages over the other options presented for this rate class.

The first advantage is that is reflects cost causality. While not a true demand rate that reflects capacity requirements by customer, it does provide an average peak capacity requirement through the use of the on-peak usage variable component of the charge.

Second, the approach aligns with the time of use rates for the commodity. Customers are already familiar with this, and introducing an on peak time of use distribution rate would reinforce the rewards for reducing consumption in on peak hours. For this to be effective, the time periods for the time of use distribution rates need to be the same as for the commodity rates. LPMA submits that the Board should consider a mid peak rate as well for distribution cost recovery. This would even more closely align the capacity related rates to the commodity rates and provide more incentive to move consumption to the off peak period rather than out of the on peak period to the mid peak period.

The Staff paper notes that bill presentment is out of scope of this paper. However, for this option to work, customers need to see the different rates for on and off peak use, just as they do for the different time of use categories for the commodity. Without this clear illustration of the price differentials and keeping the distribution costs rolled up in one figure would be illogical in that it would subvert the ability of customers to make changes.

In addition, LPMA submits that the on and off peak times should be adjusted at the same time as the TOU commodity periods are changed (summer and winter).

With respect to Option 3, LPMA submits that this has potential, but has a number of issues with the proposal as presented.

First, the first block charge should not be lower than the fixed charge. This goes against the recovery of the fixed costs on a cost causality basis. In other words, even a customer who does not use the system but is connected to it, should pay their fair share of the fixed costs. This would result in a customer at lowest block of consumption paying something in excess of the fixed monthly service charge.

Second, LPMA is concerned with the potential costs to CIS systems to make consumption to date available to customers within a billing month. Customers would need this in order to see where they are in their energy use relative to the block they are in. This information is readily available for cell phone and internet plans.

A third potential issue with Option 3 is that billing cycles are not always the same length. For example, one cycle might be 30 days long and another could be 32 days in length. Customers would not be happy if they went over their allowed usage because of the addition of a day or two in the length of the cycle.

Another issue is whether the customer could change the energy block that they select each month. Since energy consumption can vary significantly from month to month over the summer, fall, winter and spring, customers may want to change plans on a regular basis.

Finally, for this option to be effective and meaningful, the bill presentment would have to be changed. Any overage costs would have to be shown separately from the block charge or the customer will not see the impact of their overages. In addition, all the available blocks should be shown on the bill, with their rates, so the customer can readily see the options available to them.

D. GENERAL SERVICE OVER 50 kW

For same reasons as provided above in the GS < 50 class, LPMA does not support the use of Option 4 (minimum bill).

LPMA believes that either Option 5 or 6 are reasonable approaches to be taken for this rate class. In both cases, the fixed monthly service charge is based on cost causality based on the Boards' cost allocation model minimum system with PLCC adjustment.

Both options also reflect the recovery of customer connection costs through non-coincident demand charge, which LPMA supports. As a result, in terms of the fixed costs and the connection costs, both options adhere closely to cost causation.

The only difference between the two options appears to be an off peak charge (Option 6) in place of the anytime charge (Option 5).

Staff has indicated that it is interested in comments on whether the NCP rate should be a monthly maximum or some kind of ratchet that would reflect an annual peak. LPMA submits that since this component of the charge is to reflect the costs related to customer connection costs, and appears to be the same in Options 5 and 6.

Since the connection costs are essentially fixed, LPMA believes that the NCP should be based on an annual maximum, not a monthly maximum. The connection costs do not change from season to season, but the use of a monthly maximum would result in increases and decreases in this component of the monthly bill. This would result in a higher rate (since the sum of the monthly billing determinants over a year would be less than the annual maximum times twelve). This would result in higher costs being recovered from customers that have a relatively steady monthly maximum (high load factor), while decreasing costs for those customers that have a peaky load (low load factor).

As an example consider two customers that have the same maximum annual peak. In theory, these customers should pay the same amount for customer connection costs. If one of the customers has a high load factor, they will pay close the maximum amount each month. If the other customer does not approach this annual peak in several months of the year, then they will pay less in those months, yet the cost to serve them are the same as for the high load factor customer. On the other hand, if the rate is set based on the maximum annual billing determinants, both customers would pay the same amount each month. LPMA submits that this outcome is more just and reasonable.

It is not clear to LPMA if the NCP is calculated based on all hours or just over peak hours. LPMA believes that based on cost causality, it should be based on all hours. The costs for the customer connection are not dependent on whether power is consumed in on peak or off peak periods.

LPMA submits that an alternative approach is to base the demand rate for the peak charge on a contracted quantity rather than any version of the NCP. This would be similar to the approach used in the natural gas industry where the large customers have a Contracted Demand ("CD"). This is a contracted amount between the gas distributor and the customer and represents the maximum amount of gas that the distributor is required to deliver to the customer on any given day. If the customer takes more gas than they have contracted for, then a penalty charge applies to the amount taken in excess of their contracted demand. Customers can calculate their CD based on the capacity of their gas fired equipment and the operation of that equipment.

A similar approach could be implemented for large electricity customers, but instead of the maximum take in a day, the maximum would be on an hourly basis. A customer would calculate the maximum electricity demand based on their specific equipment and circumstances and be billed on that amount. Any excess in the peak demand would incur a penalty rate. This approach would work for the Intermediate and Large Use classes, as most of these customers already have such contracts with their gas utilities. It could also be implemented for the GS > 50 kW classes. For example, many large multi-residential buildings in London have contracts with Union Gas that sets out the CD for gas use. This CD is used for billing purposes as well as design day purposes.

Under Option 6, it would appear that using a contracted CD would eliminate the need for both a peak charge and an off peak charge and would be more consistent with cost causality. Regardless of when a customer uses their maximum capacity, the customer connection costs should be recovered in the same manner.

With respect to the anytime charge in Option 5, LPMA notes that the charge would be based on the coincident peak. While customers can control their non-coincident peak ("NCP"), customers do not have the same control over their coincident peak ("CP"). They do not know when a coincident peak is going to happen, or if it has happened, on any day, never mind over the course of a month. In other words, customers have little, if any, ability to avoid or minimize the anytime charge.

LPMA is concerned that this could significantly increase the volatility in costs on a month to month basis. In one month a customer could get hit with a high cost because of their use of the system on the coincident peak, while in the following month, this cost could be significantly less. This change could be driven by actions of the customer, but would more likely be the result of nothing but luck or the demand of other customers in all rate classes contributing to the coincident peak - neither of which is within the control of the customer.

Another issue that may arise is comparability across distributors. Many organizations have electricity accounts in a number of distributors. The coincident peaks can vary significantly across distributors depending on a number of things, such as the makeup of the customers. For example one distributor with a large industrial sector is likely to have a different coincident peak from a distributor with no industrial customers. A general service customer could, therefore, be hit with a high anytime demand cost in one distributor and a low anytime demand cost in another. This would lead to customer confusion as to why the charges were significantly different in one utility compared to another.

On the other hand, Option 6 does not appear to adequately address the recovery of the contribution to peak capacity requirements. This is because there is no charge based on the coincident peak. At the same time, depending on the load profile, a customer with a high off peak load could be paying more than a customer with a low off peak demand even though their peak demands are the same.

Option 6 appears to adequately recover the customer connection costs, since those costs are based on maximum demand, regardless of whether it is in on peak or off peak periods. In other words, the NCP, or contracted demand, would be reflected in the billing determinants in one part of the rate or the other. However, it is unclear to LPMA how Option 6 recovers the peak capacity costs. This is clear in Option 5, but not in Option 6.

Rather than using the coincident peak demand in Option 5 and a mix of on and off peak demand in Option 6 to recover the peak capacity costs, LPMA submits that options that should be studied include the NCP calculated over only the peak hours, and the average of the coincident peak over a longer period than one hour per month (for example, three highest coincident peaks in a month). The goal would be to use a proxy to recover the capacity related costs, while providing for more stability in costs.

With respect to the issue of a broad peak period or a narrow peak period for Option 5, LPMA submits that the peak period should be consistent with a narrower peak than that used to define the transmission peak period for the network pool.

As Staff notes, distributor peaks differ from one another based not only on the composition of load but on the composition of generation within the distribution territory. For example, solar penetration can have the impact of shifting the peak period to later in the day. It may also have an impact on the level of the peak demand in this later period.

LPMA submits that allowing distributors the flexibility to address its own system peak is appropriate. This would reflect more closely cost causality, which LPMA supports. It would also allow flexibility for changes in the future as more renewable generation is added to some distributors, causing changes in their system peaks. Hence, LPMA supports Option 5B over 5A.

LPMA does not support Option 6B. Offering free off peak capacity ignores the fact that the customer connection costs are for the most part fixed and driven by the size of the connection. Just because the capacity of connection is only fully utilized in the off peak period does not mean it does not need to be recovered. This approach would lead to cross subsidization of customers within the GS > 50 kW class. In this instance, a customer with a large connection cost (because of a higher demand) could end up paying less than another customer with a low connection cost just because they have a higher demand in the off peak hours.

G. CREDITS FOR DISTRIBUTED ENERGY RESOURCES

LPMA is not providing any comments on this section as it appears that the distributed energy resources would be larger than any GS < 50 and most GS > 50 customers would contemplate, given they are not in the generation business.