67 Yonge St.
Suite 1040
Toronto, ON M5E 1J8

APPrO
ASSOCIATION OF POWER PRODUCERS OF ONTARIO

Re: Rate Design for Commercial and Industrial Customers:
Rates to Support an Evolving Energy Sector EB-2015-0043
Comment on Staff Report to the Board of February 21, 2019

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

Dear Ms. Walli,

Attached please find the comments of APPrO in the above-noted matter. We thank you for the opportunity to participate.

APPrO looks forward to working with the OEB on this and future initiatives. Both I and other members of the Association would be happy to discuss this submission in greater detail should you have any questions or concerns.

Sincerely,

Jake Brooks
Executive Director

Cc Dave Butters, Laurie Reid, Rachel Anderson, Lenore Robson, Travis Lusney

Association of Power Producers of Ontario (APPrO)

Comment on Staff Report to the Board of February 21, 2019

Rate Design for Commercial and Industrial Customers:
Rates to Support an Evolving Energy Sector EB-2015-0043

Introduction

The Association of Power Producers of Ontario (APPrO) appreciates the opportunity to submit comments to the Ontario Energy Board (OEB) on the Staff Report to the Board on Rate Design for Commercial and Industrial Electricity Customers: Rates to Support an Evolving Energy Sector (the Staff Report) released on February 21, 2019. The Staff Report is part of the OEB's consultation for Commercial & Industrial (C&I) rate design (EB-2015-0043). Previously, the OEB had released a staff discussion paper in March 2016 (the Staff Discussion Paper 2016) for stakeholder comment and received significant feedback from interested parties. APPrO submitted detailed commentary on the Staff Discussion Paper 2016 and continued engagement through the ad-hoc individual consultation sessions that were held from 2016 to 2017. APPrO was also active in related electricity consultations on revenue decoupling for residential customers, load displacement generation, the Renewed Regulatory Framework for Electricity (RRFE), and distributed generation.

APPrO is a non-profit organization representing electricity generators in Ontario. APPrO members produce nearly all the power generated in Ontario from facilities of many types, including gas-fired, hydroelectric, nuclear, solar and wind energy. APPrO members are customers of transmission and distribution utilities in Ontario, and many have current distribution connection applications in development or underway. APPrO members often experience challenges associated with building and operating distribution connections, challenges which can in many cases be helped or hindered as a result of the business models and practices adopted by Local Distribution Companies (LDCs or "distributors") in response to the prevailing rate design solutions.

APPrO offers the following comments regarding the Staff Report and looks forward to continued fruitful participation in this and related OEB proceedings. APPrO agrees with Staff that "In response to the changing landscape and customer expectations, a new electricity rate design is needed to enable more customer choice in investments and technology while ensuring that reliability of the electricity distribution system is maintained"[1].

[1] Staff Report, Feb 21, 2019, pg. 2.

Objectives

The OEB's cover letter for the Staff Report outlined the following objectives for the new commercial and industrial rate design[2].

1. Facilitate customer adoption of technology to manage energy use and costs, including the installation of distributed energy resources
2. Increase efficiency of the system by encouraging cost effective investment in distributed energy resources
3. Maintain fairness in the recovery of costs of maintaining a reliable and flexible distribution system and ensure that customers who install distributed energy resources do not shift costs to other customers
4. Facilitate investments to modernize the grid in a paced and prioritized manner that will support customer choice and efficiency

APPrO, in general, supports the OEB objectives and believes they are focused appropriately to maximize the value for customers, distributors and all other interested parties. However, APPrO is concerned that the OEB objectives may warrant further refinement, and that not enough information has been shared on potential prioritization of the objectives. As part of further consultation on rate design and other aspects of Ontario's electricity regulatory framework, APPrO suggests that the OEB provide both clarity and direction on prioritization of these objectives, to ensure successful evolution of the regulatory framework is achieved in the near future.

APPrO would recommend a refinement to the third objective, reading as follows:
3. Maintain fairness in the recovery of costs of maintaining a reliable and flexible distribution system and ensure that customers who install distributed energy resources do not shift net costs to other customers, recognizing that DER's often provide cost savings and system benefits that must be netted against unadjusted costs.

Recommendations to the Board on the Staff Report

APPrO has reviewed and analyzed the Staff Report in detail and concluded that the proposed rate design does not successfully achieve the OEB objectives as stated. At a high level, APPrO's analysis has determined the following effectiveness of the proposed rate design as it relates to each of the OEB objectives. (See Table 1 below).

[2] Staff Report Cover Letter, Feb 21, 2019, pg. 1 & 2.

OEB Stated Objective	Recommendations Effectiveness
Facilitate customer adoption of technology to manage energy use and costs, including the installation of distributed energy resources	The recommendations do not yet facilitate customer adoption of technology and proactive management of energy use. In fact, the Staff Report analysis[3] forecasts over-charging such customers. However, the fixed charge approach applicable to the lower volume classes is a helpful and appropriate basis for further development.
Increase efficiency of the system by encouraging cost effective investment in distributed energy resources	The recommendations do not yet encourage investment in DERs that increase the efficiency of the system. This is because no price signals are offered, and significant uncertainties are created. Investment depends in part on achieving clarity on the method for ascertaining whether an investment will be deemed economic.
Maintain fairness in the recovery of costs of maintaining a reliable and flexible distribution system and ensure that customers who install distributed energy resources do not shift costs to other customers	The recommendations only result in protecting distributor revenues, through an incremental and excessive charge (CRC) on DER-hosting customers, which often runs counter to objectives 1, 2 and 4. Further, the lack of a peak demand price signal allows free-riding amongst customers who choose not to manage their demand. Further, in order to ascertain if costs are being shifted to certain groups, net costs must be analyzed, a process that requires benefit estimation as well as cost assessment.
Facilitate investments to modernize the grid in a paced and prioritized manner that will support customer choice and efficiency	The recommendations do not support this objective for reasons stated in item 2 above.

Table 1: Summary of APPrO Analysis of Proposed Rate Design Effectiveness

APPrO strongly recommends that the Board instruct OEB staff to conduct further consultation with the following understandings:

- <u>Integrate C&I Rate Design with the new consultations</u>: The OEB has launched two integrated consultations (i.e., Utility Remuneration (EB-2018-0287) and Responding to DERs (EB-2018-0288)) following the receipt of the November 2018 recommendations and report from the OEB's Advisory Committee on Innovation. The C&I rate design consultation should be integrated with these new consultations since all are intertwined with the significant changes occurring in Ontario's electricity sector (i.e., adoption of DERs, changing LDC business models, facilitating customer choice, and managing innovation).
- <u>Establish a comprehensive engagement plan with target timeline</u>: The existing rate design influences investment decisions by customers and distributors today. The time required to resolve updates to the C&I rate design will compound the likely cost of potentially inefficient decisions expected to be made in the short term. APPrO recommends that a comprehensive engagement plan be established by staff for consultation. The engagement plan should have a target timeline that includes the following activities i) jurisdictional review of best practices for utility business models with DER integration, ii) multiple stakeholder sessions to discuss integration with other consultations and to ensure stakeholder feedback/analysis is appropriately reflected in proposed changes to Ontario's regulatory framework, and iii) a formal process to present, review and finalize new rate designs before enactment.
    - Any significant change in rate design must be paired with a suitable methodology to assess or estimate the benefits of DERs. In other words, rate design should be based on a cost-benefit

[3] Staff Report, Appendix B, Feb 21, 2019, table 5 & 6, pg. 9.

analysis of DERs to the distribution system which may or may not conclude that additional charges are required for customers with DERs.

If the Board feels it must resolve rates for at least some customer classes in the short run, APPrO recommends that the Board proceed with the staff recommendation to “Establish a fixed distribution charge for commercial customers with demands under 10 kW who’s use of the distribution system is like residential customers” and to “Implement a demand charge mode, rather than the current volumetric charge, for distribution service for all commercial and industrial customers with demands greater than 10 kW to reflect these customers use of the system” basing demand charges on Coincident Peak rather than Non-Coincident Peak. However other aspects of the rate design recommendations in the Staff Report are highly problematic and should be the subject of substantive consultations as described above.

The April 2015 report identified enduring principles for rate design

APPrO commends the Board and staff on its policy of moving to fixed charges for most customer classes. The OEB policy enunciated on April 3, 2015 in “A New Distribution Rate Design for Residential Electricity Customers” (the April Report) stands as an enduring set of principles for rate design. It was entirely appropriate and highly constructive to recognize that “customers primarily value connection to distribution services and the essential service of billing.” The Board articulated a foundational principle for future distribution rate design when it said, “there are few costs in the distribution system that change with the energy that flows through the grid. Distribution assets are designed to deliver power reliably and have by their nature long service lives and largely fixed costs.” That said, the basis for fixed charges should be determined by the customer’s Coincident Peak wherever that is feasible. Coincident peak charges provide the most accurate price signals for both customers (in terms of the value of managing demand) and for the LDC (in terms of anticipating capital requirements). While fixed rates may be an appropriate interim measure for small and medium volume commercial customers, APPrO anticipates that rates for these customer classes will over time transition to rates based on demand charges, also set on the basis of Coincident Peak.

It is appropriate that all connected customers contribute to the fixed costs of the system in proportion to the maximum demand that they place on the system. To simplify calculations, the size of a customer’s connection is often used as a proxy for their maximum demand or Coincident Peak demand. Considering the importance of ensuring that customers are not unduly hindered from making investments that may change their load pattern, even potentially turning them into suppliers of some services to other customers at appropriate times, rate designs should not discourage customer-driven investments.

In order to consistently maintain adherence to these rate design principles, it became apparent during APPrO’s analysis of the Staff Paper that some parts of the recommended rate designs will need to be re-considered.

Reasons for Further Consultation on C&I Rate Design

APPrO's review and analysis of the Staff Report concluded that the proposed rate design does not achieve the OEB's stated objectives. APPrO has grouped the reasons for further consultation into four primary categories, detailed below.

Reason #1: The Staff Report and consultation process did not appropriately reflect stakeholder feedback

The Staff Discussion Paper 2016 presented six rate design options for four different customer classes[4]. Stakeholders were requested to provide feedback on each of the potential design options along with the applicability to each customer class. While it is possible to provide feedback generally on which design proposals are more attractive, APPrO believes it is virtually impossible to draw specific conclusions from such a broad number of options. For example, APPrO's submission to the Staff Discussion Paper 2016, focused commentary on the six rate design opinions and was not able to provide detailed commentary on applicability by rate class. In APPrO's opinion, the next step of the engagement process would be most effective if focused on an appropriate subset of two to four options, so stakeholders would have the opportunity to delve deeper into trade-offs, impacts, and implementation issues for the primary design options identified.

Perhaps most importantly, a significant number of stakeholder responses to the Staff Discussion Paper 2016 were supportive of Coincident Peak (CP) as the fundamental charge determinant for rates. Support for CP based charges was broad and included both entities advocating for DERs and rate-payer groups who largely viewed CP charges as a fair and equal cost allocation method. See below examples of responses from stakeholders to the Staff Discussion Paper 2016.

- The **Association of Major Power Consumers in Ontario** (AMPCO) stated that it "agrees in principle with current OEB thinking that providing incentives to customers to reduce peak capacity optimizes use of the current system and optimizes investment needs for long term cost containment."[5] AMPCO specifically supported options including coincident peak charges, stating as follows:

> In AMPCO's view, this rate design option best responds to cost causality and the uniqueness of customers and how and when they use energy and the distribution system, while still sending the right price signals to appropriately incent customers to use the grid more efficiently and shift demand to off-peak periods. Some AMPCO members (Intermediate/Large Use customers) use more energy during the peak and others use more energy off-peak and their contribution to the peak varies. Some customers use energy at a steady rate, for example, 24/7 and 365 days a year. This rate

[4] Staff Discussion Paper, Mar 2019, Table 1, pg. 15.
[5] AMPCO Comments, May 27, 2016, pg. 2.

design recognizes the differences between customers and in AMPCO's view is fairer and leads to better economic outcomes for customers. Board Staff indicates that this option is expected to be fairer and provide more revenue stability than peak and off-peak alone. AMPCO submits this option is the most cost-effective.

This Option also provides more accurate price signals in that it reflects connection demand and capacity demand, two of the main distribution system cost drivers and it differentiates between the two. Active customers are rewarded for reducing peak capacity.[6]

- The **Building Owners and Managers Association** (BOMA) also supported coincident peak charges.[7]

- The **Canadian Federation of Independent Business** (CFIB) supported charges "which gives users who peak in peak hours a very strong incentive to shave their peak, but also gives an incentive to users who peak outside peak hours to manage their peak."[8]

- The **Canadian Solar Industries Association** (CanSIA) supported the 2016 proposals including coincident peak charges and "rate design options to help ensure that customers contributions to peak demand are charged appropriately."[9]

- **Energy Storage Ontario** (ESO) also supported coincident peak charges because this would "offer prosumers a direct incentive to load shift for the benefit of the consumer and the system" and "decrease or defer the cost of distribution and transmission upgrades."[10]

- The **School Energy Coalition** (SEC) expressed support for the objectives of cost causality and efficiency, stating as follows: "Any change to C/I rates will produce winners and losers. Schools are not necessarily fixated on being in the winners group in that process. Winners and losers should be based on sound ratemaking principles, including in particular cost causality. In the long run, that is better for all customers."[11]

It appears that the Staff Report has not sufficiently addressed the opportunities available through CP based charges, or the stakeholder comments in this area. In particular, APPrO is concerned that no further analysis has been performed on the suitability of CP charges for meeting the OEB objectives for C&I rate design. Perhaps most confusing is the fact that the current Staff Report recommendations appear to be inconsistent with the initial conclusions in the Staff Discussion Paper 2016:

> *By basing rate design on the cost drivers for distribution systems, it will align the interests of distributors and customers. Customer decisions in their own interest are also in the interest of*

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[6] AMPCO Comments, May 27, 2016, pg. 4.
[7] BOMA Comments, May 27, 2016, pg. 7.
[8] CFIB Comments, May 27, 2016, pg. 8.
[9] CanSIA Comments, May 27, 2016, pg. 4.
[10] ESO Comments, May 27, 2016, pg. 7.
[11] SEC Comments, May 27, 2016, pg. 9.

the distributor. Actions that customers take to reduce their bills will lower long term investments by distributors and help contain future distribution system costs.[12]

Specifically, the OEB stated that the current commercial and industrial rate design is "out of sync"[13] because "**a price that does not differentiate between demand that drives cost and demand that does not, fails to align the interests of the customer and the distributor**."[14] Finally, the Staff Discussion Paper 2016 stated:

Individual customers have rarely been charged based on their actual contribution to coincident peak but rather, an assumed contribution to peak based on customer classifications and load profiles. With the increase in the number of customers who have time sensitive metering, OEB staff believes it is possible to more closely align the rate design with the cost driver.[15]

In short, by overlooking CP-based rate designs, the staff report appears to have missed an opportunity to reflect the core principles of cost causality along with stakeholder feedback. APPrO believes this warrants a full reconsideration, especially in light of the broader implications in terms of the close connections between this consultation and other consultations (i.e., Utility Remuneration and Responding to DERs).

Finally, the consultation process that the OEB conducted after receiving feedback on the Staff Discussion Paper 2016 was flawed for other reasons. Meetings with stakeholders were ad hoc and limited in scope with little opportunity for participants to prepare prior to attending. Further, the method used for selection of stakeholder participants, to say nothing of the exclusion of others, was unclear to many. Little or no information was shared publicly in terms of the staff plans for continuing to consult or for using the feedback from stakeholders to justify a proposed C&I rate design. Finally, the ad-hoc consultation process was spread over a long period of time. More than 2 years has transpired since publishing the Staff Discussion Paper 2016. The Staff Report attempts to draw conclusions from the drawn-out consultation process without considering a formal discussion on those conclusions.

Reason #2: Analysis performed is insufficient as presented in Staff Report

The analysis presented in the Staff Report focused on the impact on five LDCs (i.e., Orangeville Hydro, Powerstream, Toronto Hydro, Hydro One urban, and Hydro One rural) as well as an additional LDC (Entegrus) for CRC impact only. Ontario has over 60 LDCs spread across the province. The LDCs selected by the OEB for the Staff Report are not an appropriate cross section of distribution customers. No LDCs from Northern Ontario, Eastern Ontario or Southwest were assessed in the Staff Report. Further, Powerstream is no longer a stand-alone LDC and has been amalgamated into the newly formed Alectra as of January 2017, over two years since the merger has concluded.

The analysis presented focuses primarily on impacts to bills and does not assess whether the proposed rate design will achieve the OEB objectives. Specifically, the Staff Report states:

[12] Staff Discussion Paper, Mar 2016, pg. 2.
[13] Staff Discussion Paper, Mar 2016, Section B.2 title, pg. 6.
[14] Staff Discussion Paper, Mar 2016, pg. 6.
[15] Staff Discussion Paper, Mar 2016, pg. 6.

The recommended rate designs will in staff's view:

- *support innovation for customers by ensuring all commercial and industrial customers of every class can reduce their bill through conservation of the commodity,*
- *allowing some customers to reduce their bill through lowering overall demand through conservation, and*
- *allowing customers who do not have the opportunity to reduce their bill through lowering demand to benefit from a simpler, more predictable bill.*

The recommended rate designs will increase efficiency of the system by encouraging economic decisions regarding investment in distributed energy resources. The designs will ensure that customers who install distributed energy resources do not shift costs to other customers and maintain fairness in the recovery of costs of maintaining a reliable and flexible distribution system.

The recommended rate designs will facilitate investments to modernize the grid in a paced and prioritized manner that will support customer choice and efficiency.

Given these broad statements by OEB staff, APPrO would have expected comprehensive analysis to support the claims being made. No analysis has been presented to support the proposed rate design. Further, no analysis has been presented that compares and contrasts the selected rate design to other options presented in the Staff Discussion Paper 2016.

Finally, analysis in the Staff Report has focused almost exclusively on assessing the impact to customer bills. No analysis has been performed to consider the broader benefits that a new rate design could have for customers as a whole. For example, no assessment has been completed on the magnitude of cost savings for all customers from deferred distribution system investment. At a high level, APPrO believes an assessment of CP demand charges versus non-coincident peak (NCP) demand charges would demonstrate that there is the potential for significant savings for all customers if CP charges were adopted. This conclusion is not far from the suggestions by OEB staff in the Staff Discussion Paper 2016. The OEB staff's own analysis showed how NCP demand charges are not an appropriate signal to incent response from customers to reduce coincident peak demand consumption. Figure 1 below from the Staff Discussion Paper 2016 demonstrates the frequency and magnitude of customers that are charged on-peak rates for off-peak use. In the staff's words, "*when the blue line is below the red line, the customer is charged peak rates for off-peak use*"[16]. APPrO expected analysis performed in the Staff Discussion Paper 2016 to be expanded upon for the Staff Report.

[16] EB-2015-0043, Staff Discussion Paper, March 31, 2016, p. 6.

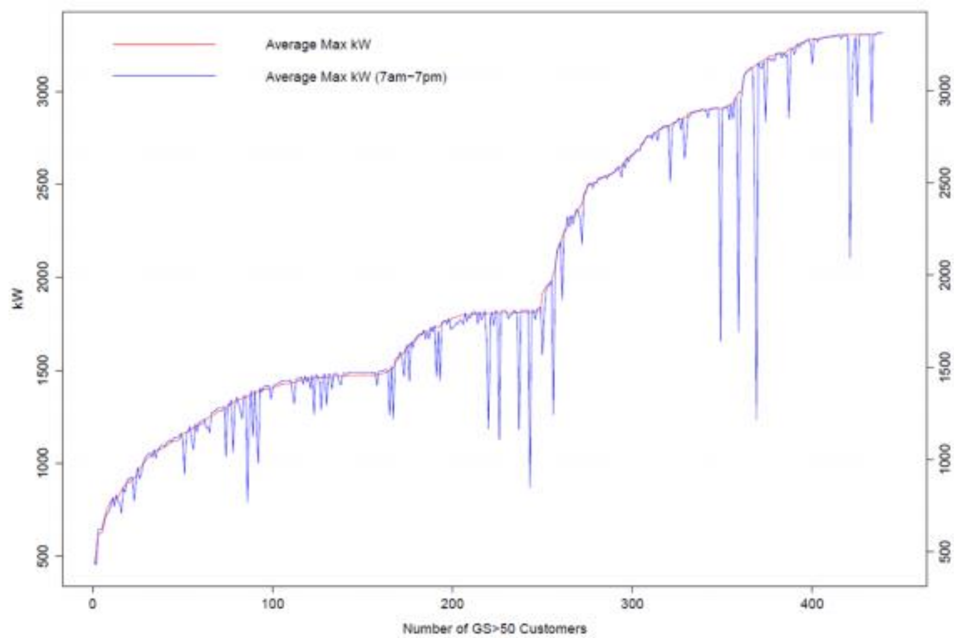

Figure 1: GS>50 customers billed demand compared to peak demand (7am to 7pm)[17]

Reason #3: No justification or analysis presented for the unexpected introduction of the CRC

The Staff Discussion Paper 2016 presented six rate design options in addition to raising the concept of DER credits. None of the rate design options discussed a concept of a province wide standby charge or CRC. While the CRC was discussed in ad-hoc meetings with selected stakeholder groups in mid-2017, no further discussion or analysis has been shared broadly with stakeholders. Further, no analysis has been presented on how the CRC design achieves the four OEB objectives or why the CRC design is the best approach for standby-rates. Options for the related quantification of DER Credits for use in rate making were not developed, even though they were referenced in the 2016 paper and in the latest staff paper. In other words, the concept of a province wide standard charge of this nature has not been adequately developed or presented to stakeholders for feedback.

Reason #4: No assessment of comparable rate designs in other jurisdictions

The C&I rate design consultation has been ongoing for almost 4 years, 3 years since the initial Staff Discussion Paper 2016 was published. Change in the electricity sector around North America has been occurring rapidly during this period. Many of the changes in other jurisdictions are worthy of consideration in the Ontario context. For example, the state of New York's Reforming the Energy Vision (REV) initiative is reshaping how Non-Wire Alternatives (NWAs) are treated by traditional utilities and regulators.

[17] EB-2015-0043, Staff Discussion Paper, March 31, 2016, p. 7.

The design components in the proposed rate design (e.g. continued use of NCP demand charges, shift to fixed charges for GS <10KW, and adoption of the CRC) have not been adequately compared to rate design options recently considered in other jurisdictions. To meet the challenges of a changing electricity sector and to achieve the OEB objectives, Ontario should draw from lessons learned in other jurisdictions, and seek to ensure that best practices are adopted. Further, fundamental changes may be required to address systematic issues challenging the industry. For example, the decision to maintain the current customer classes (i.e., GS <50kW, GS >50kW, large customers) has not been reviewed to determine if there is a better option. Alternatively, it appears that no optionality in rate design for LDCs or customers has been considered by Staff.

Deficiencies of the proposed rate design

APPrO strongly recommends that the proposed rate design outlined in the Staff Report undergo further stakeholder consultation. In addition to the reasons listed above, APPrO has identified the following deficiencies with the proposed rate design.

No analysis has been provided on benefits or costs of Coincident Peak charges

The vast majority of distribution system costs are caused by investments to resolve capacity constraints due to coincident peak loading. For example, investments for installation of new transformation capacity are derived from forecasts of coincident peak demand on those assets. Further, given that Ontario's distribution infrastructure is aging and must be updated in many cases, coincident peak usage is a direct indication of the degree to which existing capacity should be expanded, maintained or shrunk (i.e., whether the asset replacement should be at a higher or lower capacity). As noted in the Staff Discussion paper, distribution systems are rarely influenced by energy flows and instead are driven by peak demand requirements (i.e., how big the pipe needs to be to supply maximum flow). The Staff Discussion Paper stated "Actions that customers take to reduce their bills will lower long term investments by distributors and help contain future distribution system costs"[18]. **Coincident peak charges provide broad benefits to all rate-payers as reductions in peak demand reduce or defer system investment costs.**

Cost causality principles are an established part of electricity rate design. In general, customers should pay for the portion of system costs that they cause. Cost causality principles have the additional benefit of incentivizing customers to respond to price signals that reflect anticipated future costs. CP demand charges increase the efficiency and cost-effectiveness of distribution systems by signaling customers to reduce demand during peak demand periods. The staff report has not presented any analysis to assess the amount of benefits CP demand charges could provide to all rate-payers.

The Staff paper raises the concern of potential cost shifting:

> *The current rate design of fixed and volumetric charges does not align well with the changing use, expectations and value to some customers. It can lead to uneconomic decisions by the*

[18] EB-2015-0043, Staff Discussion Paper, March 31, 2016, p. 2.

*customer and shifting of costs to more traditional customers who are either unable to, **or choose not to**, adopt new technologies.*[19]

While there is a potential for cost shifting due to uneconomic decisions by some customers, the lack of an appropriate price signal representing the cost of maintaining and expanding the system ensures that there is inefficiency and no benefit capture possible. Customers that are not informed of or impacted by the higher cost of consumption during constrained hours will not adjust their consumption patterns or seek out potential net benefit investments. Under these inefficient conditions, the distribution system must be expanded in a way that burdens all customers with higher costs. However, coincident peak charges dissuade inefficient behaviour, in this case leaning on the system or free riding. Without CP, customers are not rewarded for economically efficient decisions that would be beneficial to them and all customers as a whole. See Figure 2 below for an illustrated example. **In short, rejecting coincident peak charges will increase system costs for all customers.**

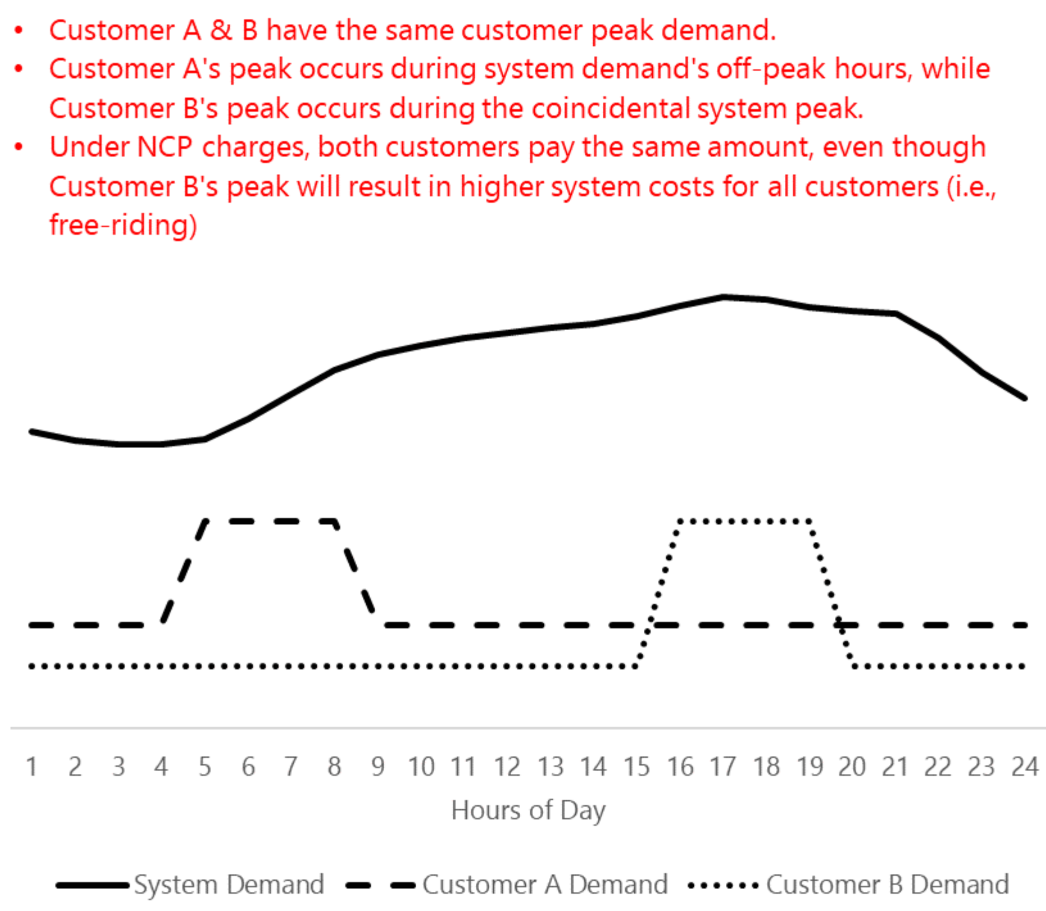

Figure 2: Example of cost shifting under NCP rate design

Looking at the issue another way, DERs may result in a gross cost shifting to customers that choose to take no action. However, the DERs also produce benefits available to all customers such as deferred system investments if given the appropriate price signal. Therefore, when considering the impact of

[19] Staff Report, Feb 21, 2019, p. 3.

cost shifting, the assessment must include an appropriate net Cost Benefit Analysis. If DERs displace or delay spending in a way that sufficiently benefits all customers, there is no net cost shifting. Although there is wide consensus on the benefits of Coincident Peak rate designs in terms of supporting economic behaviour and investment decisions, APPrO recommends that the OEB conduct research to determine the extent to which the use of CP charges can be expected to result in cost reductions over the long term for each of the various classes of distribution customers.

APPrO notes there are many forms of coincident peak rate design that could be used depending on each distribution system characteristics (e.g., demand rate during time periods, stacking of tiered demand rates, coincident ex-post demand rates).

The CRC is not fully formed and it is not clear how the CRC is appropriate to the Ontario regulatory framework

Review of the proposed CRC design by APPrO has identified a number of flaws. First, the CRC design seeks to establish a simplistic and standard amount of reserve capacity across the province for Load Displacement Generation (LDG) by technology type. This approach does not reflect any assessment, not even a probabilistic assessment, of the performance of the LDG or the distribution network the LDG is connected to. For example, consider a large customer with LDG connected to a sub-transmission system. Sub-transmission systems typically have higher redundancy and system capacity built for aggregate demand[20] (i.e., coincident peak). Determining reserve capacity in a prescribed province-wide fashion without considering how that capacity is shared with other customers is not fair treatment to the customer.

Second, the Staff Report states the following:

> *Staff are now recommending that the proposed calculation reflect the expectation that generation is displacing load based on using a capacity factor. A capacity factor (CF) is the ratio of a generator's actual output over a period of time, to its potential output if it were possible for it to operate at full nameplate capacity continuously over the same period of time. Capacity factor is specific to the technology and more specifically to how the generator is run.*

Annual capacity factors are an inappropriate metric for CRC and have little correlation with peak demand reduction. The figure below provides an illustrated example of two resources with the same annual capacity factor but different production profiles, therefore very different reserve capacity needs. LDG A has consistent output across the whole time period, while LDG B has no output except for maximum output during a short span of the time period.

[20] The Staff Discussion Paper 2016, Mar 2016, pg. 6. stated the sizing of distribution system clearly: *Aggregated demand affects the system and equipment that serves more customers. The higher the connection voltage in the system, the more customers are contributing to the sizing of the distribution system equipment.*

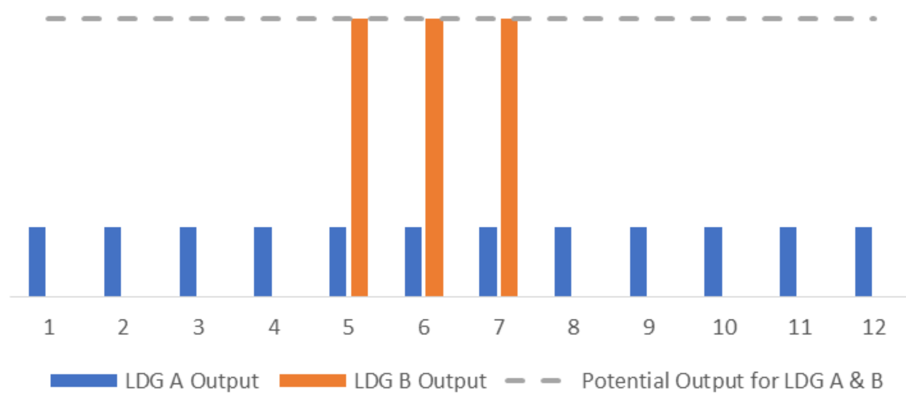

Figure 3: Illustrated example of different LDG energy production profiles for same annual capacity factor

Using annual capacity factor to determine the amount of reserve capacity required presents significant risks of over collection or under collection by distributors.

During the Staff Report stakeholder meeting on March 7, 2019, OEB staff implied that annual capacity factor was not meant to be used, but instead a form of "effective capacity to supply during Ontario's system peak demand" should have been used. Ignoring the error in the Staff Report, using an effective capacity based on serving Ontario's system-wide peak demand is also inappropriate. Each distributor service territory has different coincident peak conditions. Therefore, the amount of reserve capacity required is different for each distributor. For different LDG technology types, the effective capacity will change depending on where in the province it is located. This is particularly true for variable output renewable resources. For example, solar generation energy production profiles are different for projects located in southern Ontario compared to northern Ontario. Further, distribution system coincident peaks change from summer peaking in the south to winter peaking in the north. The result is that a solar generation facility in northern Ontario may be charged a CRC even though no reserve capacity is required because the customer's load profile during coincident peak remains the same (i.e., no sun is shining during the distribution system's winter peak).

Third, combining the CRC design with NCP demand charges will very likely result in many customers being double charged. Consider output from a facility like LDG A in Figure 3 above. While the customer is being charged a CRC to maintain reserve capacity, whenever the customer takes the LDG off-line for maintenance, their NCP demand will increase and the customer distribution charge will increase. However, if the maintenance outage occurs in off-peak hours when the distribution system is lightly loaded, the customer is effectively double paying for capacity. The OEB's own analysis in the Staff Report demonstrates that there is a likelihood that the LDC will over-collect through the CRC[21]. Over-

[21] Staff Report, Appendix B, Table 1 & 2, Mar 2016, pg. 9.

collecting from customers who choose to make investments in energy management is of course contrary to the objectives set out in this rate design initiative.

Finally, the Staff Report has provided no examples from other jurisdictions that support the design as put forward. There are many examples in other jurisdictions of progressive standby rate designs that reflect the value of their grid connection but recognize that there is less need for capacity to be allocated to that customer. Those facilities should be offered the potential for lower distribution rates. If the customer does not perform as expected they are expected to pay higher distribution charges.

With respect to the Staff Report comments on Maintenance Service and Bypass fees, there are similar fundamental concerns that warrant further consultation. The concept of maintenance service in which the customer essentially contracts not to take more than a specified amount of demand, even to the point of using a load limiter, is viable in principle - although it can be problematic depending on implementation details.

The concept of instituting generally applicable bypass charges is not conducive to customer investments or facilitating innovation. Such charges can only be justified if the proposed customer investment is demonstrably uneconomic using a standard, transparent, rigorous and independent economic test. Reduction of LDC volumes is not in itself evidence that a given investment is uneconomic. The essential question that an economic test must answer is whether the entire customer base is better off in the long term with the new investment. Given the importance of facilitating customer-driven investment, innovative and otherwise, exit fees should apply only in very unusual circumstances, when significant tests have been met, and customers should be able to assess their exposure to such onerous fees easily and relatively quickly before committing to a significant new investment that might affect their load patterns. These significant rate design proposals warrant further consideration and stakeholder consultation. Significantly, some of these issues are related more closely to capital planning than to rate design. The primary reason they arise in rate design discussions is because a proposal for exit fees was included in the current rate design recommendations.

Cost assessment methods appear to overlook benefits of DERs

The proposed rate design does not consider any of the benefits DERs provide to distribution systems.

The following is a partial list of some of the benefits that DERs can offer to distribution systems and therefore all customers:

- Avoided or deferred upstream transmission costs and local distribution costs
- Loss reduction (e.g., transmission losses, transformation losses, distribution system losses)
- Reliability functions in support of Distribution System Plans (DSPs) and/or Integrated Regional Resource Plans (IRRPs)
- Increased efficiency of the distribution system by expanding the ability to serve more load customers with existing distribution assets
- Ancillary services to the distribution system (e.g., voltage support, voltage stability, reactive power / power factor correction, improved power quality, etc.)
- Resiliency support
- Ability to serve certain customers where conventional wires expansion isn’t feasible

New services and technologies offered by third parties are allowing customers to change their consumption from the distribution system without changing their internal electricity needs. In many cases the services offers do not require customers to do anything and are therefore independent of their consumption decisions. The technological capability of mutually exclusive consumption decisions can offer significant benefits to the distribution system, but requires a price signal to inform consumption decisions. In other words, determining distribution rate design in isolation from distribution system benefits will lead to higher costs for all customers.

APPrO strongly recommends that any rate design change must only be adopted along with a comparable methodology to assess or estimate the benefits of DERs. In other words, rate design should be based on a cost-benefit analysis of DERs to the distribution system which may or may not conclude that additional charges are required for customers with DERs.

The proposed rate design does not address the growing pressures for change

The fourth objective of the OEB states that modernization must occur in a paced and prioritized manner. The Staff report recognized the need for caution and that changes should not be rushed for the following reason:

> *We also heard very strongly in consultation that these customers were already dealing with many changes, both in general business conditions and the electricity bill. These customers also pointed out that they had often made previous business decisions for investments and operations based on managing their bill, including to participate in the Industrial Conservation Initiative peak demand reduction program. Changes to the rate design could undermine those decisions.*[22]

Developers face many obstacles that inappropriately reduce the amount of economic DER added to the system. These inappropriate obstacles include a) gross load billing on some wholesale charges, b) the high cost and uncertainty of interconnection (studies, protective relaying, lines and transformers, etc.) and c) the lengthy and uncertain amount of time required to go through all the study, design and construction steps with the LDC and/or Hydro One. If the current staff proposal were to proceed without changes, then developers would be obliged as well to consider the potential costs and risks of the proposed CRC charges. APPrO understands that some of these barriers lie outside of distribution rates, and that the Board is only looking at distribution rates at this time. However, these barriers have economic consequences affecting the efficacy of certain rate design choices, and we would encourage the Board to collaborate on reducing the barriers in all these areas.

The report's apparent approach of overlooking coincident peak rate design does not adequately serve cost causality principles or investment requirements. Stakeholder feedback indicates that customers are investing to manage energy uses based on the existing rate design. To achieve the key objective of modernizing the grid and increasing efficiency of the system, the new rate design must align customer investment decisions with cost drivers of the system. Further, there is an urgency to making these changes since leaving the rate design in its current form supports inefficient and potentially seriously problematic investment decisions by customers and distributors. While a paced and prioritized manner

[22] Staff Report, Feb 21, 2019, p. 36.

of development is beneficial for managing change, delaying appropriate rate design sends inappropriate investment signals to customers in the short term causing inefficiencies in the short and long term. DERs can help customers manage their energy use and provide services to grid operators. It must be facilitated by suitable rate design to reflect the net benefit the system can offer customers and grid operators. Without a suitable rate design, DER investments may be abandoned or improperly designed. In summary, time is of the essence in updating the rate design, since customers and service providers are acting on the existing rate design which will otherwise result in inefficient investment decisions by customers and distributors.

Other jurisdictions are recognizing the need to move forward expediently to address the evolution of the electricity sector. For example, the Alberta Utility Commission (AUC) launched a distribution system inquiry to address similar issues the C&I rate design is attempting to address. Some stakeholders requested that the AUC delay the inquiry because of the many significant changes underway in the Alberta electricity market. The AUC responded appropriately that it plans to continue the inquiry "***because of the growing economic and technological pressure for change to the distribution system*"[23].**

Exit fees cannot be allowed to over-ride high priority objectives for the system

Any jurisdiction which creates a significant risk that exit fees will be charged on projects that are otherwise economic is actually driving away investment, loudly broadcasting inappropriate economic signals throughout the economy, discouraging innovation, and deeply damaging its ability to adapt to future conditions. While it's necessary to ensure that uneconomic investment does not take root, given that such initiatives would fundamentally rely on shifting costs to other consumers, customers are always better off when investment in economic new technology proceeds and when regulatory conditions are not weighted against such investment.

It is inevitable that some cost shifting will occur as the technology landscape changes. The critical question in this regard is whether each class of customers receives enough net benefit to more than offset any cost shifting. The primary underlying challenge for regulators is establishing rational and transparent tests to determine which investments are economic and which are not, before large amounts of capital are committed, and before investment moves to other jurisdictions.

Any system for exit fees must be designed, using a comprehensive stakeholder consultation process, with full regard for the objectives of encouraging innovation, while instituting fair and rational measures for preventing uneconomic investment. The measures for preventing uneconomic investment must be evidence-based, objective, transparent, widely understood, the product of substantial stakeholder consultation, and have the effect of reducing uncertainty.

[23] AUC Proceeding 24116, Scope and Process for the Distribution System Inquiry, March 29, 2019, pg 3.

Conclusion and Recommendations

APPrO appreciates the opportunity to submit feedback to the Board on the Staff Report. The rapid adoption of emerging and innovative DERs are changing the way customers consume electricity. The changes to customer consumption patterns and their growing ability to respond to price signals requires a broad re-think on how Ontario's power system is planned, financed, operated and maintained. The re-thinking must include consideration for the following broad components of Ontario's electricity regulatory framework:

- Cost allocation: which customers pay for what investments;
- Rate design: how are customers charged for system costs;
- Utility remuneration: how network owners receive revenue and returns for efficient operation and investment in their networks; and
- Compensation for DER benefits: how DERs should be measured and compensated for services they provide to network operators.
- Investment signals: how to ensure that common carriers receive accurate signals as to the appropriate type and size of future capital investments.

Due to growing economic and technological pressures for change to the electricity system, action must be taken promptly. To optimally achieve the OEB objectives, the OEB and stakeholders must assess the impact that changes made to each component may have on the other components. Efficient modernization, investment, and effective integration of DERs requires a regulatory framework addressing all components in a way that is transparent to all concerned distributors and customers.

APPrO's assessment of the Staff Report has concluded that the proposed rate design does not meet the objectives the OEB has laid out. APPrO recommends further consultation under pre-defined terms. The new consultation should occur together with the newly launched intertwined consultations by the OEB (i.e., Utility Remuneration and Responding to DERs) with specified timelines. In summary, APPrO recommends the following actions for the Board:

- Instruct Staff to re-open consultation on C&I rate design starting with a comprehensive jurisdictional review of best practices
- Instruct Staff to develop a comprehensive engagement plan for the intertwined consultations to ensure all components are addressed holistically
- Any significant change in rate design must be paired with a suitable methodology to assess or estimate the benefits of DERs.

Appendix 1:

Examples of customer investments where DER is required because the LDC is unable to provide comparable service options

APPrO members have reported that in many cases Ontario based customers need DERs because the local LDC can't expand service on a timely and/or economic basis. The list below provides some current examples where a customer is proceeding with a DER solution because of constraints acknowledged by the local LDC.

1) Agriculture installation, located in southern Ontario: New facility, 10 MW, plus a 5 to 15 MW expansion in the near future. Natural gas fuel, growth in new market opportunity.

2) Mining operation, located in Northern Ontario: New facility, 50 MW, natural gas fuel, new mining operation.

3) Mining operation, located in Northern Ontario: New facility, 10MW, diesel fuel, accommodate plant start and operation prior to utility connection.

4) Agriculture installation, located in Southwestern Ontario: Expansion, 10MW, natural gas fuel, growth in new market opportunity.

5) Agriculture installation, located in Southwestern Ontario: Expansion, 20+ MW, natural gas fuel, growth in new market opportunity.

6) Agriculture installation, located in Southwestern Ontario: Expansion, 15MW, natural gas fuel, growth in new market opportunity.

7) Agriculture installation, located in Central Ontario: Expansion, 12 MW, natural gas fuel, growth in new market opportunity.

These amounts represent projects at an advanced state of development known to one particular supplier in Ontario. The actual totals in the market are likely much higher and growing.

Appendix 2

Summary of previous APPrO recommendations[24] to improve the assessment of generation-related benefits to the system.

"The Generator Co-ordination Group envisions a set of metrics that will assess the following network benefits (without limitation) on a consistent basis: loss reduction, avoided or deferred upstream costs, local reliability (including contributing to the kind of regional reliability reinforcements sought by Hydro One), ability to serve more load customers, voltage support, reactive power, VARs, improved power factor, other ancillary benefits, black start, storage, statistical probability of using lower cost local resources more frequently, and ability to respond to local needs and provincial policy directions."
- *Submission from APPrO and other members of the Generator Co-ordination Group to the Ontario Energy Board on the Renewed Regulatory Framework for Electricity, May 4 2012, EB-2010-0377, EB-2010-0378, EB-2010-0379, EB-2011-0043 and EB-2011-0004.*

The following excerpts from the above submission provide further context and reasoning for the above recommendation:

14. The GCG (Generator Co-ordination Group) recommends that the Board adopt and mandate a broad cost/benefit approach for the assessment of new grid infrastructure investments. The new approach should be robust, clear and result in the assessment of not only long term costs, but also long term, sector-wide benefits in the determination of significant infrastructure investment decisions and the allocation of related costs. It should always consider generators as recipients of transmission and distribution services, who warrant customer service quality standards and measures. It should also be proactive in facilitating efficiencies through cooperation by requiring distributors and generation proponents to work cooperatively to minimize the costs of new connection, facilitate the efficient operation and connection of existing and new generation assets, and mandate a paced and measured approach to new distribution and transmission grid investments with a defined dispute resolution process.

...

it is difficult to design rules and regulations that can be universally applied to all electrical network planning processes. For this reason, it is particularly important for responsible parties in any of the concerned agencies to be able to access consistent and reliable data on which to base decisions. The area in which consistent data has been most lacking is in the assessment of upstream benefits of network investments.

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[24] From comments provided on behalf of the Generation Coordination Group (GCG) to the OEB in its RRFE proceeding, April 2012. The GCG was comprised of the following member organizations: the Association of Power Producers of Ontario (APPrO), the Biogas Association (formerly the Agri-Energy Producers Association of Ontario, (BGA)), the Canadian Wind Energy Association (CanWEA), the Canadian Solar Industries Association (CANSIA), the Canadian District Energy Association, which was further described in Appendix; and the Ontario Waterpower Association (OWA).
http://www.ontarioenergyboard.ca/OEB/_Documents/EB-2010-0377/APPro_Comments_20120504.pdf

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20. In order to ensure that distributors have high quality information on the value and benefits of a network investment under consideration, they will need access to a consistent set of metrics that have been reviewed and tested in a regulatory context and which make use of common terminology. This will facilitate comparisons between distributors and improve transparency of planning processes at whatever level they occur (within the distributor, regionally or provincially).

21. The Generator Co-ordination Group envisions a set of metrics that will assess the following network benefits (without limitation) on a consistent basis: loss reduction, avoided or deferred upstream costs, local reliability (including contributing to the kind of regional reliability reinforcements sought by Hydro One), ability to serve more load customers, voltage support,
reactive power, VARs, improved power factor, other ancillary benefits, black start, storage,
statistical probability of using lower cost local resources more frequently, and ability to respond to local needs and provincial policy directions.

22. The Ontario Energy Board received useful evidence on a proposed SSCBM in the EB-2007-0630 proceeding: Development of a Standard Methodology for the Quantification of DG Benefits, July 31 2008. We strongly urge the Board to facilitate the detailed development of a broad SSCBM[25] for distribution and transmission infrastructure investments starting with the proposed approach outlined therein.

[25] System/Societal Cost-Benefit methodology (SSCBM)