June 14, 2023

Ms. Nancy Marconi
Registrar
Ontario Energy Board
2300 Yonge St, 27th Floor
Toronto, ON M4P 1E4

Dear Ms. Marconi:

Re: **Electric Vehicle Integration (EVI): Ontario Energy Board Delivery Rates for Electric Vehicle (EV) Charging**

As part of the Minister of Energy's 2022 Letter of Direction and full endorsement to proceed as quickly as possible, the Ontario Energy Board (OEB) is continuing its ongoing EVI initiative work to facilitate and "issue guidance to LDCs on system investments to prepare for EV adoption" as well as "consider distribution rates for EV charging (including demand charges)". As part of its EVI planning the OEB retained Power Advisory (PA) to prepare analysis and present a report on "*Electric Delivery Rates for Electric Vehicle Charging"*. On May 24, 2023, the OEB and PA jointly presented these recommendations to the broader stakeholder community including local distribution companies (LDCs). As Ontario's independent energy regulator, the OEB sets the delivery rates energy utilities can charge and has an obligation to set fair, just, and reasonable rates, allocating costs responsibly amongst classes to those who are directly benefitting from those investments.

The scope of the EVI study was limited to electricity delivery rates for distribution-connected commercial EV fleets (e.g., public transportation, delivery trucks, etc.) and public direct current fast charging (DCFC) stations (public DCFCs) which are considered commercial and industrial class consumers. Electricity delivery rates for commercial and industrial (C&I) customers are primarily based on the customer's peak demand (PD). Demand charges reflect the maximum amount of power a customer uses over a specific interval, usually 15-minute increments, during a billing cycle. C&I customers are charged based on demand because doing so reflects principles of cost causality. Peak demand is a major driver of costs for a distribution system, and therefore customers who have higher peak demand (i.e., whose usage creates the need for more infrastructure and thus more costs for the system as a whole) are charged more. While generally accepted as appropriate for most C&I customers, this rate design can be problematic for customers whose usage profile is atypical. It is assumed in this evaluation that all EV commercial fleets and public DCFCs have unique load profiles, which under current delivery rate structure have bills that are more impacted by demand-based charges vs. energy-based charges. Load factor is the average demand divided by non-coincident peak (NCP) demand,

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where NCP demand represents the highest peak demand drawn by a customer in a monthly period regardless of the time the peak occurs.

The Electricity Distributors Association (EDA) represents local hydro utilities across Ontario, Ontario's electricity customers know that their LDC is their frontline representative to the electricity system. LDCs are knowledgeable about what their customers want and, more importantly, what their customers need from both a global and specific rate class perspective. Insights into customers' existing and future needs for electricity and delivery services support LDCs in appropriately planning their distribution systems and deploying technology on an ongoing basis. Whether traditional poles-and-wires, supported by the enabling infrastructure (e.g., fuses compatible with one-way power flow) or innovative technologies (e.g., non-wires alternatives, price signals) coupled with the enabling or foundational infrastructure, LDCs have the technical skills, experience, and ability to responsibly deploy the technology that will provide the distribution service(s) customers need and want, reliably and at an appropriate level of quality. LDCs intend to meet their customers' expectations both operationally and from a rate consideration and contribute to being a 'part of the solution'.

This submission provides the comments of our members on matters arising in the above-named consultation. Our members will be directly affected by the outcome of this initiative as it will impact both the customers that members serve and the risk profile of distribution revenue streams. On behalf of all our members, we appreciate the OEB for progressing on this issue, retaining PA to assess delivery rate options and scenarios and for providing this opportunity to comment on the recommendations presented in the OEB EVI Engagement. The following submission is organized by the OEB's three areas of interest: (1) General Feedback, (2) Alternative Rate Designs, and (3) Implementation of Alternative Rates.

(1) <u>General Feedback:</u>

The report identifies and quantifies the challenge of high delivery costs for public EV charging and EV fleet charging.

We believe that any alternative rate design chosen by the OEB and that impacts the delivery rates must be fair, equitable and not give undue preference or discrimination to any one rate class. Overall focus should be on cost causality, fairness, transparency, and ease of understanding, and communication to customers. The design of the rates that are implemented should be revenue neutral and seek to reduce the amount of cross-subsidization within existing rate classes. When examining the impacts of the alternative rate design it is important to note the variation of impacts that exist amongst the sampled LDCs. Impacts for this significant EVI integration should not be narrowly scoped through a sample of LDCs, but through all LDC business operations. We strongly encourage the OEB to scope the impacts on all LDC customers (both new and existing) to be considered when evaluating new rate design.

Policy Solutions

Policy solutions that might also be pursued to address the delivery cost challenges identified in the report are direct subsidies from the government to support public policy objectives and EV charging proponents. Government incentives, subsidies, or tax-based solutions have the potential to address noted concerns, rather than altering the existing rate designs across the province and potentially provide a more open-ended attempt of capturing system impacts. These potential supports could be targeted with the specific intent of facilitating the further roll out of EV charging across the province and would provide a subset of data that would be monitored as the province moves forward with this initiative. Any rate design solutions for DCFCs and fleet charging could be more broadly applied to other customers whose load profiles occur at NCP, mostly off-peak or whose loads have a low load factor. However, as noted in the Report, there has been insufficient analysis conducted to understand the impact of potentially offering the proposed rate design alternatives to a broader set of customers. The goal of the government should be addressed in a way that supports one policy solution over the other while ensuring that rates continue to reflect cost causality.

New Delivery Rates

New delivery rates could be an appropriate and effective solution to the challenges identified if the outcomes of the rate design analysis indicate that costs are assigned based on level of costs they pose on the system. Sound and effective ratemaking principles ensure that uniform rates are applied to groups of similar customers and that those costs are allocated proportionally to the customers that caused such costs to be incurred. The PA report shows that alternative delivery rates could achieve the outcome of lowering delivery rates for some customers, but this still requires the OEB to evaluate whether the rate design would align with sound making principles and is justified and equitable. Rates can be designed for solutions to achieve a targeted policy outcome; however, distribution rate design may not be the appropriate tool in all situations and should be carefully considered for future impacts.

Implementation

Implementation costs and challenges that LDCs will face in implementing new delivery rates for EV charging consumers will depend on the changes that are proposed and the design that is chosen. These decisions are fundamental to planning the implementation impacts and the lead times provided to distributors to implement. However, the following can be generally considered for rate implementation:

- Billing System Costs: Costly billing system upgrades may be required.
- Vendor Costs: Short implementation timeframes result in higher costs.
- Metering Configuration Changes

- Metering Capital Investments
- Internal Billing System Coordination: The considered rate classes currently do not flow billing data through the billing system the same way that, for example, TOU is organized. Therefore, data would not be organized in the same method as other rate classes. System and Infrastructure changes would be required to accommodate any structure based on time of day, rather than metered consumption.
- Increased Regulatory and Financial Costs: Load Forecasting, Rate Design, Billing Determinants, Settlements, Variance Accounts, etc.
- Tracking: Dynamic and ongoing tracking of customer load factors would require new development.
- Administrative Processes: Customer determination, declarations, and rate reviews with tracking would be added to billing and customer audit procedures.
- Economies of Scale: If the new rate was not required for all LDCs, costs would be higher for those moving forward.
- Communications to customers: Added rate structures may be challenging to communicate based on complexity.
- Deferral and Variance: Consideration for DVA for implementation costs, but also revenue variances between rate plans. This is particularly critical if the intent is for there to be optionality in the rate options as there are no mechanisms to account for Lost Revenues of customers switching between plans.

Non-Rate Solutions

Non-rate solutions to the challenges identified that could be considered are demand response and load control programs that might provide incentives to EV charging customers which better align with avoided system costs. These programs give the LDC the ability to manage the EV charging load to off peak periods, reduce commodity costs and strain on system. While this could incent shifts in consumer patterns, these options might provide limited certainty regarding the customers' responsiveness and their behaviour patterns. Customers might expect to be compensated for giving up the ability to control their charging and incentives could be an added cost. Regardless, LDCs are designed to support peak. In either scenario LDCs would still build distribution system capacity requirements into their network plans to preserve greater reliability whether or not behaviour is changed in the near term by incentives.

Other Considerations

Other considerations beyond those considered in PA's report and should be considered by the OEB to address the challenges identified could be:

- The IESO's Annual Planning Outlook (APO) projections predict provincial increases from 1.5TWH to 20 TWH of new load which was not on the system before. As new load comes online, new electricity consumption patterns will be realized.

- The PA report assumes that DCFCs are unlikely to contribute to coincident peak demand. LDCs expect that public DCFCs will be utilized at times that are convenient for drivers. These times will not necessarily align with off-peak periods, and across the sector it may be that many DCFCs will charge throughout the day.

- We question the assumptions that DCFC public charging stations are unlikely to contribute to the CP, and in fact, LDCs to an extent need to plan their distribution systems (and incur costs accordingly) to accommodate a DCFC being used during a system peak due to a shift in usage behaviour. While the study required assumptions, we suggest there be further investigation as to whether the EV charger load will result in material incremental distribution costs. LDCs do not just build their distribution systems to accommodate the current coincident peak only. LDCs must plan their long-term system capacity to comfortably accommodate a forecasted maximum peak. In forecasting and determining the maximum capacity requirements, the individual potential contribution, (i.e., non-coincident peaks of new and existing customers) must be taken into consideration, given the customers' ability to change their usage patterns at any time (unless part of an LDC demand response program). To this extent, the customers' NCP/maximum potential load could lead to increased CP-related distribution costs.

Also noted during the stakeholder session, it is critical that any potential delivery rate changes be reviewed in conjunction with the economic evaluation requirements outlined in Appendix B of the Distribution System Code. Otherwise, there is a strong potential that any monthly delivery cost savings that are derived would simply be offset by higher capital contribution requirements to ensure that the new EV charging connection is economic and not subsidized by existing ratepayers. This essentially transfers the ability to pay the cost of the new EV charging connection over time to a requirement for an upfront payment. If the cost of the new connection is the same, lowering the delivery charges may not reduce the amount the customer is ultimately responsible for, and increase the deposit required for expansions.

(2) <u>Alternative Rate Designs</u>

The report proposes two categories of alternative delivery rates for EV consumers.

Considering the report's two categories of consumers and recommendations:

- **Time of Use Demand Charges: EV Fleet Charging**
- **Low Load Factor Rates: Public EV Charging**

There are multiple rate design iterations that could be pursued to address the concerns at hand. However, it will be the determination of the OEB on whether it is proper to consider rate design alternatives in the context of a particular government policy outcome in the first place (i.e., lowering rates for a particular class of customer) and these must be carefully considered, particularly where the rate setting option is targeted to the end-use of the load rather than a specific class of customers with similar patterns.

While Time of Use has proven to be an effective solution in cost recovery based on cost causality, fairness, and transparency, we believe that low load factor rates will be much less effective for cost recovery based on cost causality. Low load factor rates will benefit the eligible consumer and shift costs to non- eligible consumers. Also, public DCFCs are subject to demand from their end use customers. There is less ability to control the cost to the public for charging, and less opportunity to mitigate the impacts of charging stations on the delivery system.

PA's report shows that both options could serve the purpose of reducing delivery charges for the specified customers. We encourage the OEB to appropriately evaluate whether it is equitable and fair to offer specific rate designs targeted to specific use cases, while other customers are subject to generic rate classifications and rate design that do not address their own business cases. The fact that two rate designs need to be proposed to accomplish the policy goal of potentially reducing delivery costs for these two specific groups of customers may be an indication that rate design is not the optimal solution to address the concern. Where rate designs have been applied in other jurisdictions to address EV adoption, it has been done as a temporary, transitional measure.

Cost allocation methodology within the PA report has been based on certain assumptions. The potential increase to the non-EV consumers not on the alternative rates presented in the report does not account for potential system cost savings resulting from alternative rates. We believe that the added assumptions should also be tested, both in terms of applicability to the increasing electricity sector as well as the specifics of each distributor. That way we can determine that cost causality remains. Non-EV customers may have costs increase or decrease based on their individual peak profile.

More direct methods to achieve the policy outcome may be available such as subsidies if this is the intended goal, and these other options may avoid the complexity of designing and implementing new rates, as well as avoid the potential negative impacts on other existing electricity customers from reallocating costs. Regardless of how often customers reach their peak load, or the size of that peak, distributors are required to ensure that connection assets are sized appropriately. Customers may have a low load factor, but there is no guarantee that the customers would not put peak pressure on the system consistently outside of the design. It must be carefully evaluated whether the proposed changes are equitable for existing customers – both new and existing customers should be allocated their share of both existing and incremental costs to ensure that no undue preference is given to any customer group.

(3) Implementation of Alternative Rates:

Format and Process

We believe that, to the extent possible, the design of the delivery rates should be consistent across the province, for the following items: cost allocation methodology, billing determinants, and overall philosophy of cost causality of usage during high peak periods. Further, the rate design could be amended to allow the allocation of the individual LDC's costs and usage profiles, weighting between TOU and non-TOU delivery rates, differing LDC peak periods (i.e., Winter Peak, Summer Peak), as well as forecasted usage of affected EV customers. Consistency in the design of rates should be extended across LDCs, but the time periods should be regionally considered to accommodate potential localized differences in peaks across the province. LDCs need the flexibility to adjust the time bands as system loads change, and the IESO's electrification APO assumptions are realized.

Implementation of alternative EV delivery rates should be mandatory for all LDCs. LDCs have collaborated successfully over the years to deliver government and OEB initiatives, e.g., smart metering implementation, customer choice, MIST metering, Green Button, and Ultra Low Overnight charging. LDCs should have the ability to format and process the design in the most cost effective and beneficial methodology for its customers.

We encourage the OEB to conduct a holistic review of existing rate classes when there is sufficient data to conduct an informed analysis. The review should (without addition of rate classes) evaluate changes and alterations which could apply better cost causality, price signals and new output worksheets within the cost allocation model. Recognizing that the industry has more considerations than it did previously the cost allocation model could be updated for today's considerations. Additionally, the OEB should consider how long the rate designs are to remain.

Consumer Optionality

Alternative rates should be mandatory, particularly given that this report is prepared to address the perspectives of cost causality and differential treatment of DCFCs based on the current distribution rate structure. Consumer optionality could potentially prevent the tracking and forecasting for this subset of customers and introduce the potential for gaming behaviours. The risk of gaming from customers, forecasting and tracking can introduce risk to both LDCs and other customer groups, shifting costs inappropriately and interrupting price signals. The possible consequence should be evaluated on the weighted factor and magnitude of electricity use by these customers. Load characteristics (e.g., load size and load factor) should determine which rate class you are in. The utility should make that determination.

The cost allocation/rate design should follow existing, well established, and supported principles (i.e., Bonbright's Principles for rates). Unique load characteristics should be the driver for consideration of a new rate structure. Rate structures/not rate levels should be consistent across LDCs wherever possible. Customers should not be subsidizing other specific customers.

We furthermore believe that these rates, in principle, should be offered to customers, other than EV charger customers, that could potentially benefit from these rates by shifting their usage from peaks. However, as noted in the PA report, the assumptions in the analysis may not hold if the rate designs are offered more broadly. Therefore, we encourage the OEB to conduct further analysis of the impact of extending the rate design to all customers that would benefit before determining whether to implement the rate structure more broadly.

The premise of cost allocation and rate design is that it ultimately reflects an equitable allocation of the costs a customer should be responsible for based on their usage of the distribution system – thus, to the extent new rates are designed, approved and implemented for a certain type of customers, that delivery rate option should be mandatory, as the reason for the rate class being created and approved is that it entails the proper level of system costs being assigned to the customer group.

Allowing optionality between distribution rate classes could result in “gaming” to achieve lower charges, and greatly increase LDC revenue risk if customers are able to opt between distribution rate classes that may avail them to lower distribution charges. This type of flexibility is not generally available today under existing LDC tariffs.

It should also be noted that distribution rate class optionality is very distinct from commodity cost optionality (e.g., RPP, HOEP, Retailer etc.), as the latter costs are ultimately a pass through for the LDC and are structured in a manner that ensures full cost recovery. For example, RPP prices include recovery of variances between actual and forecast costs to ensure that RPP customers and generators are held whole.

Eligibility

Sound rate making principles indicate that alternative rates should not be offered specifically to EV charging consumers for EV charging load exclusively. However, as noted in the Power Advisory report, insufficient analysis has been done to support the broader application of the proposed new rate designs. The new rate design should be applied to all customers of that class, or not any of them. The OEB should carefully evaluate whether permitting an exclusive rate class for a particular end-use of electricity policy is equitable and examine the impacts of offering the new rates to a broader set of customers. Additionally, if new rates were to be developed for EV charging load, in the future customers may make the business case to the OEB for alternative customer specific rates. The OEB cannot expect LDCs to police/monitor whether the customer uses electricity exclusively for EV charging or for other purposes. If the goal is to ensure cost causality, demand shifting/reduction, and reducing the needs for additional/excess infrastructure expansion, the optionality basis should not be considered.

Metering

If required, the cost of separate metering for EV charging would need to be balanced with the chosen design. Based on PA's report LDCs would not incur any additional metering costs, and most meters within these rate classes already communicate in appropriate intervals. As discussed in the cost consideration section, LDCs' backend systems would require upgrades to apply billing charges appropriately to these customers. Installation of dedicated metering for DCFC or fleet separate from other customer loads would be beneficial for monitoring, and reporting purposes. This data could be used in the future to revisit design considerations, but we hesitate to develop a position on a recommendation without further in-depth analysis. This may vary depending on the customer's specific circumstances. However, separate metering and accounts would appear to be a requirement should these alternative rate designs be pursued to isolate this load from that of other existing accounts.

Conclusion

We recommend that the OEB continue to expand the analysis presented by PA to fully quantify system impacts and explore implementation costs and considerations. Rates must not embody unreasonable distinctions and should be just, reasonable, sufficient, equitable, and consistent. Rates need to be established and designed to recover revenue requirement, and cost causality must mean that the costs are recognized as being caused by a service if the costs are brought into existence as a direct result of providing the service, or the costs are avoided if the service is not provided. The OEB must determine if it is reasonable for EV charges to be treated separately from other loads, rather than as a contributor of total distribution system benefits and costs.

As noted above, demand response programs, direct government incentives, subsidies, or tax-based solutions could be more straightforward and simple solutions to address the noted policy concern and assist in developing this market, if that is indeed the intended objective. It is important to note that while LDCs are strongly supportive of means to support the energy transition and electrification, we do feel it our responsibility to move cautiously in a direction which perceives supporting any preferred rates or subsidies for a particular customer group, compared to solutions that could provide greater benefits to all customers. With stated policy intent, there may be ways to accomplish it that are more straightforward, and greatly reduce the time, effort, and risk to LDCs in needing to design and implement new rate structures. Great care must be taken in contemplating changes to traditional, principled rate design to achieve a certain policy outcome.

We wish to emphasize that the PA report is built on a matter of assumptions and is focusing on distribution rates, and neither generation rates, nor transmission rates. As infrastructure gets closer to the customer, the infrastructure is sized and maintained for the customers' peak capacity **regardless of the frequency and regardless of the time of the peak usage at the bulk system level**.

We request that given the issues identified above, and regardless of the chosen path, the OEB gives considerations for LDC implementation and customer impacts. LDCs and their customers will benefit from an appropriate lead time, clear communication materials, and thorough bill testing. Building these items into a workplan will create less burden and confusion to the implementation process. We hope that the OEB considers the alignment of billing changes, cost allocation updates, and to be coordinated amongst all parties.

We look forward to working with the Ontario Energy Board to find the most appropriate rate structure for which LDCs can successfully implement EVI in the future. Please do not hesitate to contact Brittany Ashby, Senior Regulatory Affairs Advisor, at bashby@eda-on.ca or at 416.886.4420, if you have any questions or require anything further.

Sincerely,

Teresa Sarkesian
President & CEO