PUBLIC INTEREST ADVOCACY CENTRE
LE CENTRE POUR LA DÉFENSE DE L'INTÉRÊT PUBLIC

June 14, 2023 **VIA E-MAIL**

Nancy Marconi
Registrar
Ontario Energy Board
Toronto, ON

Dear Ms. Marconi:

Re: Electric Vehicle Integration (EVI) Initiative (EB-2023-0071)
Electric Delivery Rates for Electric Vehicle (EV) Charging Report
Submission of the Vulnerable Energy Consumers Coalition (VECC)

Please find attached VECC's submission on the above referenced matter, pursuant to the Board's letter of May 31, 2023. Please contact me if any clarification is required (bharper.consultant@bell.net)

Yours truly,

W Harper

William Harper
Consultant for VECC/PIAC

cc. J. Lawford, PIAC

ELECTRIC VEHICLE INTEGRATION (EVI) INITIATIVE (EB-2023-0071)

VECC'S COMMENTS RE OEB REPORT ON

ELECTRIC DELIVERY RATES FOR EV CHARGING

INTRODUCTION

The Minister of Energy's October 22, 2022 Letter of Direction to the OEB included the following with respect to Electric Vehicle (EV) Integration:

> *"Within the context of the OEB's ongoing work to facilitate innovation in the energy sector, the previous mandate letter requested that the OEB "issue guidance to [LDCs] on system investments to prepare for EV adoption." I understand the OEB has developed its plan to enable system readiness for EV adoption, consider distribution rates for EV charging (including demand charges), and examine connection processes for EV charging stations. This includes studying barriers to EV charger connections through the Distributed Energy Resources Connection Review Working Group, updating filing requirements in December 2022 to underscore that distribution planning activities must include consideration of EV adoption, and being ready to consult with the sector on the EV charging analysis in 2023. This work has my full endorsement and should proceed as quickly as possible." (emphasis added)*

As part of its work under the Electric Vehicle Initiative, the OEB commissioned a consultant, Power Advisory, to complete an analysis of the impact delivery costs have on EV charging service providers and owners of EV fleets, and explore alternative delivery rate designs to determine how they may support EV adoption while adhering to sound ratemaking principles. Power Advisory completed and submitted its Report to the OEB on April 13, 2023[1]. Subsequently, the OEB held a virtual meeting on May 24, 2023 to present the findings of the Report to interested stakeholders and to gather feedback regarding the findings. The OEB also invited stakeholders to provide additional feedback in writing and set out a number of specific questions[2] on which it was interested in receiving input.

Set out below are VECC's written comments.

[1] Delivery Costs Report | Electric Vehicle Integration | Engage with Us (oeb.ca)

[2] See the Stakeholder Meeting; Introduction and Discussion found at Delivery Costs Report | Electric Vehicle Integration | Engage with Us (oeb.ca)

VECC's COMMENTS

VECC's comments have been organized in response to the specific questions set out by the OEB.

A. GENERAL FEEDBACK

1. POLICY SOLUTIONS: WHAT POLICY SOLUTIONS SHOULD BE PURSUED TO ADDRESS THE DELIVERY COST CHALLENGES IDENTIFIED IN THE REPORT?

In addressing this question VECC's comments first focus on the "delivery cost challenge" itself prior to addressing the "policy solutions" that should be pursued.

1.1. Delivery Cost Challenge

The Power Advisory Report (the "Report") references[3] the results of the OEB's Survey of Local Distribution Companies and EV Charging Service Providers on facilitating the integration of EVs in Ontario and the fact industry stakeholders and EV charging service providers have raised concerns about the impact of electricity delivery costs, and especially demand charges, have on EV charging infrastructure adoption – particularly for owners of commercial EV fleets (i.e., buses, delivery trucks, etc.) and public direct current fast charging (DCFC) charging stations ("public DCFCs").

The Report notes that, while the demand charges levied by Ontario distributors for General Service Over 50 kW ("GS>50") customers vary, they generally make up a significant portion of the non-commodity costs charged to GS>50 customers[4]. Furthermore, the Report notes that for Commercial EV Fleets and Public DCFCs the average rate (i.e., $/kWh) is higher than for a typical GS>50 customer[5], primarily due to the impact of the demand charges.

VECC notes that the fact demand charges make up a significant portion of the non-commodity costs is a natural consequence of the fact that for the GS>50 class:

- Transmission charges levied by the IESO and both Transmission and Low Voltage charges levied by host distributors are largely based on demand (i.e., $/kW).
- Charges for Distribution service are largely recovered based on demand, with a lesser portion recovered through a monthly customer charge.

Also, VECC does not dispute the fact that the average rate ($/kWh) for GS>50 customers will vary based on a customer's load factor, with a low load factor customer's average rate being higher due to the need to recover any demand charges over fewer kWhs.

For purposes of comparing the average rates for various EV charging circumstances to the average rate for a "typical" GS>50 customer, Power Advisory has based the load profile for a typical GS>50 customer on "an average day from hourly Ontario Demand in 2015 through 2021, net of Regulated Price Plan demand (sourced from the Independent Electricity System Operator (IESO) Smart Metering Entity) and directly connected

[3] Page 7
[4] Page 12
[5] Pages 14 and 17

industrial load (sourced from IESO public reports)."[6] There are two key issues with this profile:

- First while the derivation nets out RPP customers and directly connected industrial customers the results will still include the load for Intermediate (typically greater than 999 kW or more) and Large Use (over 5,000 kW) customers served by Ontario distributors. These customers are more likely to have 7x24 operations and therefore higher load factors than GS>50 customers.
- Second, it is VECC's understanding[7] that this profile was used to determine not only the energy use profile of a typical customer but also the billing demand. The problem with this approach is the load profile used is based on the diversified loads of all the customers such that the load factor for the profile will be higher than the load factor for the average customer included in the profile.

Both of these issues are likely to result in the load factor used for the illustrative "typical" customer being higher than that for an actual "typical" GS>50 customer such that the average rates for a typical customer as set out in Table 1, Figure 4 and Figure 7 of the Report are understated. As result, the degree to which the average rates for Commercial EV Fleets and Public DCFC's exceed the average rate for a typical GS>50 customer are likely overstated.

However, the real challenge for potential owners of Commercial EV Fleets and Public DCFCs is not the fact that their average rate exceeds the average rate for a typical GS>50 customer but rather the fact that the average rate for electricity can impact their business case and demand charges make up a significant portion of the average rate. This is particularly an issue for Public DCFCs given the currently low penetration of EVs and, hence, the current low utilization rate[8] for Public DCFCs.

Looking particularly at Public DCFC's, the Report notes that[9]:

> "*Most public DCFCs in Ontario currently price electricity sold to drivers in the range of $0.40 to $0.60/kWh.23 In terms of range added, charging an EV at $0.60/kWh is comparable to gasoline priced at $1.23/litre. In the Rural High service territory, average rates exceed $0.60/kWh when utilization falls below 4%. At low utilization, it is difficult for public DCFC operators in some areas to recover their operating costs*."

On the other hand, Figure 7 of the Report indicates that at a 5% utilization rate, only the Rural High service territory has an average rate exceeding $0.40/kWh and that at 10% utilization (or better) all service territories have average rates of less than $0.40/kWh. This would suggest that the "challenge" is not province-wide. It would also suggest that the "challenge" is more of a transitional one that will dissipate as EV penetration and the utilization of DCFCs increase.

In the case of Commercial EV Fleets, the Report notes that "average rates (i.e., per-kWh rate including both delivery costs and commodity costs, etc.) for commercial EV fleets range from $0.12 to $0.23/kWh"[10]. However, a closer look indicates that it is only in certain service territories and for certain types of fleets that the average rate exceeds

---

[6] Page 2, Table 1, Footnote #5

[7] Based on the responses provided during the May 24th Stakeholder Meeting.

[8] Page 16

[9] Page 16

[10] Page 13

$0.15/kWh. Furthermore, the Report notes[11] that "for commercial EV fleets, an all-in electricity cost of $0.15/kWh is comparable to diesel priced at $0.33/litre for lower speed fleets where EVs have the greatest efficiency advantage". Given the current price of diesel fuel[12], the fuelling costs for EV fleets would appear to be already significantly less than diesel in most cases.

The Report also references[13] a comment by one fleet owner with operations in multiple provinces who indicated that there are significant disparities in electricity costs between provinces which impacts how their company phased in the electrification of its fleet (i.e., could mean prioritizing electrification in other provinces over Ontario). However, in VECC's view, higher rates in Ontario for electrified fleets are likely as much a function of the overall higher cost of electricity in Ontario relative to other provinces[14] as the specific rate applicable to electric fleets.

As result, while clearly electricity prices will impact the business case for Commercial EV Fleets and Public DCFCs, in VECC's view the degree of "challenge" posed by current electricity delivery rates applicable to EV charging varies across the Province and by type of EV use and, in some cases, appears to be minimal.

More importantly, under current legislation it is not the role or the mandate of the OEB to set rates with a view to improving the businesses cases for private investment in specific sectors, particularly at the expense of other ratepayers/consumers. This point is addressed more fully in the following section.

1.2. Policy Solutions

Need to Align with Statutory Objectives

When it comes to electricity, policies and policy solutions established by the Board must align with the Board's statutory objectives for electricity which are set out in Section 1(1) of the *Ontario Energy Board Act*:

1. To inform consumers and protect their interests with respect to prices and the adequacy, reliability and quality of electricity service.
2. To promote economic efficiency and cost effectiveness in the generation, transmission, distribution, sale and demand management of electricity and to facilitate the maintenance of a financially viable electricity industry.
3. To promote electricity conservation and demand management in a manner consistent with the policies of the Government of Ontario, including having regard to the consumer's economic circumstances.
4. To facilitate innovation in the electricity sector.

The Report discusses how these objectives apply when considering electricity delivery rates and makes the following points:

---

[11] Page 13-14

[12] https://www.ontario.ca/motor-fuel-prices/#section-1 and https://data.ontario.ca/en/dataset/wholesale-gasoline-prices-toronto-and-new-york-harbor/resource/caa77dcb-8d6d-4795-bbee-9a9ce270af94

[13] Pages 18-19

[14] Comparison of Electricity Prices in Major North American Cities 2022 (hydroquebec.com)

- OEB Objective #1:

  "An appropriate rate design protects customers by minimizing cross-subsidization between customer classes and customers within a class."[15]

  "Some forms of rate design could be offered as an optional rate, introducing the concept of customer choice to commercial and industrial rate classes. This can be beneficial to customers, but this concept is not currently used in setting distribution rates and would add complexity to the ratemaking process."[16]

- OEB Objective #2:

  "Sound rate design produces a rate that acts as an appropriate price signal for customers. A rate would not be effective if the incremental costs caused by an EV charging customer exceeds the revenues recovered from the customer. This scenario would lead to customers demanding more than what is economically efficient to the detriment of other customers (i.e., would require cross subsidization) and harm revenue requirement stability. Conversely, rates would not be statically effective if they are greater than incremental costs to the extent that customers are discouraged from consuming electricity when the customer would not impose costs on the distribution system, and it would be economically efficient to consume. Some rate designs can create additional costs for LDCs, such as additional load analysis, new studies, or changes to billing systems. Economic efficiency should consider the regulatory burden of alternate rate structures."[17]

- OEB Objective #3:

  "An appropriate rate design should provide the proper incentive for customers to avoid contributing to peak demands. An effective rate design will incent EV charging customers to avoid contributing to their LDC's CP demands and the provincial peak demands. Practicality and simplicity issues can arise if those peaks occur at different periods. Individual customers should be incentivized to manage their peak demand to avoid the need for investments in downstream assets near the customer."[18]

- OEB Objective #4:

  "EV charging as a rapidly growing customer group. This type of customer generally has a low load factor, especially at the initial low levels of EV adoption, so its demand charges are high relative to the customer's energy consumption. This may create a barrier to entry for EV fleets and public DCFCs. To facilitate innovation in EV charging in Ontario, rates can be restructured to remove this barrier while maintaining full cost recovery.
  The demands of EV fleets can be managed by shifting charging loads to off-peak times. Public EV charging customers have less control over the timing of their

[15] Page 68
[16] Page 69
[17] Page 67
[18] Page 71

demands. An effective rate design should consider the characteristics of both types of customers to maximize innovation in the sector."[19]

VECC generally agrees with Power Advisory's assessment as to how the OEB's statutory objectives shape the applicable policy solutions when considering delivery rates for Commercial EV Fleets and Public DCFCs with the following provisos:

- With respect to Objective #2, rates are set so as to recover a forecast revenue requirement that is based on historical and current costs rates and cannot generally be set such that incremental revenues equal incremental costs. In such cases, the consideration of incremental costs/savings should focus on rates that will influence customers' decisions. For example, if the intent of TOU rates is to encourage/incent load shifting then the rate differential should reflect the incremental savings/costs that will result.
- With respect to Objective #4, when considering the OEB's role in "facilitating innovation in the electricity sector" it is VECC's view the "electricity sector" should be interpreted as the generation, transmission and distribution of electricity". It should not be interpreted as meaning the Board should be making decisions regarding the types of uses that electricity will be put to behind the meter. Having said this, if electricity is to be put to certain uses then VECC considers it appropriate for the Board to establish policies that encourage such use to be made in a way that makes more efficient/effective use of the electric system. This would include facilitating innovation that encourages such uses to shift to off-peak periods and/or use electricity more efficiently. A good example of this is CDM where LCDs participate in programs that encourage consumers to use more efficient products. Similarly, support for DERs (e.g. storage and local generation) should be based on what is good (i.e. cost effective) for the supply of electricity to customers.

In the case of electricity rates for transmission and distribution the OEB Act (Section 78(3)) also requires that the rates ordered by the Board be "just and reasonable". In VECC's view "just and reasonable" rates are ones that align with Bonbright's attributes of a sound rate structure as set out in the Report[20]. In particular, "just and reasonable rates" are rates that are cost based[21] and non-discriminatory (i.e., customers that impose similar cost on the system face similar rates). VECC notes that this view is shared by the BC Utilities Commission in its decision regarding BC Hydro's application for rates applicable to the DCFC stations it owns:

> "*We have considered BC Hydro's rate design principles and, to summarize, found that the primary consideration in setting a just and reasonable rate is to ensure that its EV charging rates are not being subsidized by its other customers. The evidence clearly shows that BC Hydro's Proposed Rates do not recover its cost to provide those services and BC Hydro acknowledges this to be the case. Because of this under-recovery and the requirements of the GGRR, customers of other BC Hydro services subsidize this shortfall and, as a result, the rate is*

[19] Page 71
[20] Pages 65-66
[21] Both in terms of being derived from the approved revenue requirement and reflecting the principle of cost causality (i.e., customer should pay for the cost they cause electric system to incur)

subsidized. The Panel therefore considers this leads to an unlevel playing field in what is otherwise a competitive EV charging service market and, as a consequence, the Proposed Rates are not just and reasonable."[22]

Overall VECC considers appropriate policies and policy solutions with respect to delivery rates for Commercial EV Fleet and Public DCFC customers that align with the OEB's statutory objectives/requirements to be ones that:

- Address situations where Commercial EV Fleet and Public DCFC customers are paying more than their fair share of delivery costs based on the principle of cost causality.
- Encourage Commercial EV Fleet and Public DCFCs customers to adopt charging practices that lead to a more efficient use of the Province's electric system.
- Are practical to implement and readily understandable by Commercial EV Fleet and Public DCFCs customers.

Power Advisory's Approach

In VECC's view Power Advisory's stated approach to selecting and analyzing alternative rate options for delivery charges seeks to align with the above requirements:

> *"Alternative rate design options were developed with the aim to better align charger utilization, LDCs' costs of servicing those chargers, and the electricity bills that charger owners must ultimately pay, while also recognizing the differences between the two use cases."*[23]

At the same time various comments throughout the Report could be interpreted as subscribing to a view that one of the Board's objectives in considering delivery charges for by Commercial EV Fleet and Public DCFCs customers should be promoting growth in these uses. Examples of this sentiment include:

- *"Customers with a low load factor are less likely to have their demand coincide with system peak but currently pay the same demand charge as any other customer in the class, better aligning these customers' delivery rates with the costs they cause to the system <u>could provide an opportunity to stimulate growth and economic development in those industries</u>."*[24] (emphasis added)
- "*This report suggests that the introduction of a TOU demand charge for commercial EV fleets would more fairly allocate distribution costs across the general service customer base; that reallocation would lower a commercial EV fleets' total electricity bills by 15% to 20%, <u>bolstering the economics of fleet electrification in a manner consistent with government policy</u> while better linking delivery charges with cost causality, and aligned with best practices for ratemaking*."[25] (emphasis added)

In both cases, while bolstering the economics of EV charging and stimulating growth in the related industries may be a desirable consequences of changes in the electricity delivery rates charged Commercial EV Fleet and Public DCFCs customers, in VECC's view they are not an appropriate criteria for the Board to use in the design of rates. Rather, as discussed above, the design of the rate should focus on:

---

[22] BCUC Decision and Order G-18-22, page 36

[23] Page 2

[24] Page 46

[25] Page 47

- Addressing whether Commercial EV Fleet and Public DCFC customers are currently paying more than their fair share of delivery costs rate based on the principle of cost causality.
- Encouraging Commercial EV Fleet and Public DCFCs customers to adopt charging practices that lead to a more efficient use of the Province's electric system.
- Ensuring the rates are practical to implement and readily understandable by Commercial EV Fleet and Public DCFCs customers.

Subsidized Rates

During the May 24th Stakeholder meeting a suggestion was made that the Board should consider "subsidizing" the delivery rates in order to improve the economics for Commercial EV Fleet and Public DCFCs customers. Absent a change in legislation and/or specific regulations directing the OEB to do so, it is VECC's view that the Board does not have the jurisdiction to approve "subsidized" rates for a particular end-use on the basis that the end-use concerned represents a "preferred" use of electricity. As discussed above, in VECC's view this is not the intent of the Board's legislated objective "To facilitate innovation in the electricity sector". Furthermore, its runs counter to the Board's legislated objectives and requirements, specifically those related to:

- Protecting the interests of consumers with respect to price and
- Approving rates that are just and reasonable.

Moreover, on this point, VECC does not consider a Minister's Letter which endorses an OEB plan to "consider distribution rates for EV charging (including demand charges)" as overriding or negating the OEB's objectives and requirements for approving rates as set out in current statutes.

Need for Consistency in Policy Approach Across Customer Classes

In VECC's view the OEB's policy and approach to rate design needs to be consistent across customer classes. In the case of the Power Advisory Report, the following quotes reflect the view that distribution costs are related to the level and time of usage and therefore are drivers of cost causality:

- "*Electricity delivery rates for commercial and industrial (C&I) customers are primarily based on the customer's peak demand. Demand charges reflect the maximum amount of power a customer uses over a specific interval - usually 15 minutes - 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*."[26]
- "*Reducing the cost of off-peak charging is also consistent with principles of cost causality, given that there are hours of the day in which the distribution system experiences reduced demand compared to peak hours; charging at those hours would therefore be expected to create fewer system costs then charging at peak*."[27]

[26] Page 1

[27] Page 64

However, this perspective is inconsistent with the rationale of the Board in its policy document outlining the rationale for a Residential fixed delivery charge:

> "*The actual cost to provide distribution service to a residential customer does not change much if the customer's usage goes up or down. For example, no matter how much electricity a residential customer uses, that customer still needs a meter, a connection to the nearest distribution pole, the poles and wires that bring electricity from the bulk system, and a place in the customer service computer system*."[28]

In VECC's view the perspective taken by Power Advisory better reflects cost causality as it applies to distribution rates.

2. <u>NEW DELIVERY RATES: TO WHAT DEGREE WOULD THE INTRODUCTION OF NEW DELIVERY RATES BE AN APPROPRIATE/EFFECTIVE SOLUTION TO THE CHALLENGES IDENTIFIED?</u>

The questions posed in Section B (Alternative Rate Designs) deal specifically with the two rates designs put forward by Power Advisory. As result, VECC interprets this question as asking more generally about degree to which the introduction of new delivery rates would be an appropriate/effective solution to the challenges identified.

Appropriate Solution

In VECC's view the introduction of new delivery rates is an appropriate solution if their design adheres to the VECC's comments regarding objectives and requirements as set out in the previous section.

Effective Solution

VECC questions the ability of new delivery rates to be an effective solution for <u>all</u> Commercial EV Fleet and Public DCFCs customers. They may be an effective solution for some Commercial EV Fleet and Public DCFCs customers. The reasons for this are two-fold:

- In the case of Commercial EV Fleets, Report notes[29]:

  > "*This report focuses on commercial EVs with a predictable overnight charging pattern that have some flexibility in the timing of their charging demand. Not all commercial vehicles meet this description. There are many different usage patterns*."

  One of the reasons for their being many different types of usage patterns is that there are many different applications for Commercial EV Fleets. The Report considers three different usage patterns[30] (Beverage Delivery, Food Delivery and Bus Depot). However there a likely many more usage patterns associated with Commercial EV Fleets.

  As a result, it not likely that all types of Commercial EV Fleet customers would be able to immediately benefit from a rate design using a TOU Demand Charge unless the peak period was limited to the few hours which captured those times when most

[28] EB-2012-0410, A New Distribution Rate Design for Residential Electricity Customers, page 10
[29] Page 54
[30] Page 34

customers were not charging. However, as discussed below[31] it is questionable if a short peak period would capture the utility "peaks" that drive the costs underpinning the TOU Demand Charge.

In the case of Public DCFCs, the illustrative rate design developed by Power Advisory assumes that there is a linear relationship between the customer's load factor and the degree to which the customer's peak load will be coincident with the system/utility peak(s). As discussed below[32], this assumption is most likely incorrect and the peak load for Public DCFCs is likely to be more highly correlated with system/utility peaks such that, after further analysis, low load factor rates are likely to be higher than suggested in the Report.

- For those Commercial EV Fleet customers that would not immediately benefit (or see only minor benefit) from a TOU Demand Charge, it is suggested that they could reduce their electricity delivery charges by shifting some/all of their current on-peak charging to the off-peak period. However, as noted in the Report[33], "real-world EV fleets have heterogeneous schedules, and not all fleets will have enough flexibility to avoid a given peak period to the same extent as the profiles shown here."

  The Report states[34] that the current average utilization rate for Canadian Public DCFCs is 5%. However, the utilization rates at individual stations vary widely as demonstrated by data collected by BC Hydro regarding its 50 kW DCFC stations for the period April 1, 2019 to March 31, 2020 which showed that the maximum number of charging sessions per month was almost twice the minimum number of charging sessions per month[35]. As a result, the load factors and the resulting savings experienced by individual Public DCFCs are likely to vary widely.

Also, while the proposed Low Load Factor Rate for Public DCFCs may address the cost issue faced by these customers it does nothing to incent such customers to manage their usage during the period. VECC recognizes that the owners of the Public DCFCs are not the users and there may be little that can be done by the owners to manage when the DCFCs are used while maintaining user satisfaction. However, the Low Load Factor rate provides no incentive to do so.

3. IMPLEMENTATION: WHAT COSTS/CHALLENGES WOULD LDCS FACE IN IMPLEMENTING NEW DELIVERY RATES FOR EV CHARGING CONSUMERS?

In VECC's view, LDCs are the ones best placed to address this question. However, given that both Commercial EV Fleet charging and Public DCFCs are both relatively new uses of electricity and this usage is expected to grow, VECC anticipates that key challenges faced by LDCs will include the availability and currency of adequate data on

---

[31] See Section B1.2
[32] See Section B2.2
[33] Page 34
[34] Pages 14-15
[35] BC Hydro's Public Electric Vehicle Fast Charging Rate Application, Exhibit B-5, BCOAPO 1.9.4.2 (https://docs.bcuc.com/Documents/Proceedings/2021/DOC_62668_B-5-BCH-Responses-to-Interveners-IRs-No1.pdf)

both types of EV charging users[36] and the LDC's system characteristics/cost drivers in order to: i) initially design the new delivery rates[37] that properly reflect each LDCs circumstances and ii) adjust these rates going forward as usage grows. Indeed, with the anticipated level of growth in the coming years the design of these new delivery rates may have to be revisited more frequently than simply when rates are "re-based" every five years or more.

More generally, in VECC's view, should the Board decide to approve new delivery rates for EV charging consumers (or other innovative rate designs) then it is important that an evaluation of such rate designs be undertaken[38] after an initial implementation period. Such an evaluation would assess the success of innovative rates in achieving their intended objectives, whether the initial assumptions used in the design of the rates were reasonable, whether the initial rate designs continued to be appropriate and whether future evaluations should be required.

4. <u>NON-RATE SOLUTIONS: ARE THERE OTHER NON-RATE SOLUTIONS TO THE CHALLENGES IDENTIFIED THAT SHOULD BE CONSIDERED SUCH AS OPTIMIZATION OF OVERALL ENERGY USE, LOAD CONTROL PROGRAMS OR INVESTMENTS IN DISTRIBUTED ENERGY RESOURCES?</u>

In this case, VECC views the Commercial EV Fleet charging and Public DCFCs customers as being best placed to address the question. However, VECC anticipates that, since there are many different types of customers (e.g. beverage fleets, delivery fleets, bus depots, etc.) that will using Commercial EV Fleet charging and each will have its own unique business requirements, there are no generic answers. However, each of the suggested non-rate solutions may have some applicability.

5. <u>OTHER CONSIDERATIONS: BEYOND THE CONSIDERATIONS DESCRIBED IN THE REPORT, WHAT ELSE SHOULD THE OEB BE CONSIDERING TO ADDRESS THE CHALLENGES IDENTIFIED?</u>

Distribution System Code: Expansion/Economic Evaluation Requirements

During the May 24th Stakeholder meeting it was pointed out that the Distribution System Code's section on Expansions (Section 3.2) and the associated economic evaluation/capital contribution requirements could eliminate any reduction in delivery costs provided to Commercial EV Fleet and Public DCFCs customers. The relevant sections of the Distribution System Code are set out below:

> *"3.2.1 If a distributor must construct new facilities to its main distribution system or increase the capacity of existing distribution system facilities in order to be able to connect a specific customer or group of customers, the distributor shall perform an initial economic evaluation based on estimated costs and forecasted revenues, as described in Appendix B, of the expansion project to determine if the future revenue*

---

[36] This would include the number of users and their current load profiles.

[37] Including any adjustments need to address the lower revenues from the customers being billed using the new delivery rates

[38] The Board could direct that LDCs implementing the rates to undertake such evaluations or the Board could initiate a generic review requesting input from LDCs that had implemented the rates.

from the customer(s) will pay for the capital cost and on-going maintenance costs of the expansion project.."

"3.2.4 The capital contribution that a distributor shall charge an embedded distributor or a customer other than a generator to construct an expansion shall be equal to that customer's share of the difference between the present value of the projected capital costs and on-going maintenance costs for the facilities and the present value of the projected revenue for distribution services provided by those facilities. The methodology and inputs that a distributor shall use to calculate this amount are described in Appendix B."

"3.2.4A Where an expansion involves an upstream transmission asset that has been deemed by the Board to be a distribution asset pursuant to section 84 of the Act, a distributor shall not require a capital contribution under section 3.2.4 or section 3.2.27 from a load customer with a non-coincident peak demand of less than 5 MW."

As VECC understands it, the purpose of these sections is to fairly apportion costs for expansion between existing and new customers. In VECC's view there is no need to depart from these requirements when considering electricity delivery rates for Commercial EV Fleet and Public DCFCs customers. In considering this issue VECC also notes:

- The requirement for a capital contribution applies only to distribution facilities and, more specifically only facilities operating as less than 50 kV unless the customer's load exceeds 5 MW (which will likely not be the case for most Commercial EV Fleet and Public DCFCs customers). As a result any reductions offered in RTSR portion of the customers delivery charges (or the equivalent if the connecting transformer is owned by the LDC) would not affect the economic evaluation and subsequent capital contribution requirements. It is only the reductions in the distribution portion of the delivery charge that will impact the economic evaluation.
- In the case of Commercial EV Fleets, those already connected to or lying along existing distribution facilities are unlikely to trigger a significant need for new facilities if their charging load has been shifted to the off-peak period.
- On the other hand, Public DCFCs customers, particularly those locating along major thoroughfares could well trigger the need for new or expanded facilities. However, in this case, the assumption is that the customers' load factors (and delivery charges) will increase over time as the utilization of the stations increases. As a result, the impact on the economic evaluation will be limited to this "transition period" while the customer's utilization rate is increasing. If the Board decides to proceed with the Low Load Factor Rate (in some form) it would likely assist both LDCs and Public DCFCs customers if a common approach is established as to how utilization rates at the Public DCFCs were expected to increase in this initial transition period.

Overall Costs/Benefits

In its Report Power Advisory notes:

> *"To the extent that loads respond to a TOU demand charge by changing their consumption profile, there may be system-wide savings in capacity,*

transmission, distribution, and energy costs. These potential additional savings were not quantified in this analysis." (page 3)

"In addition, there may be potential for system-wide cost savings if there is a stronger incentive for commercial EV fleets with flexible schedules to shift their charging to off-peak times." (page 14)

In considering the benefits from the load associated with Commercial EV Fleet and Public DCFCs customers, in VECC's view it is important to note that the focus of the OEB's initiative in this area is EV delivery rates. New Commercial EV Fleet and Public DCFCs customer loads do not create any benefits at the transmission or distribution level. However, they do potentially create new costs. At the same time, there is an opportunity to reduce these costs if the new Commercial EV Fleet and Public DCFCs customers can be encouraged to shift to the off-peak charging load that would otherwise occur in the peak period. Furthermore, the costs imposed by these customers may be less than the costs imposed by a typical customer with the same billing demand. It is these two issues that the proposed rates are seeking to address. As a result, from a delivery cost perspective there are no additional benefits that can be ascribed to these customers.

The same observations generally apply in the case of generation capacity and energy costs. However, any benefits Commercial EV Fleet and Public DCFCs customers provide due to their demand being less coincident with the system peak or by shifting load to the off-peak period are system-wide benefits that treated/paid for as such (i.e., by all Ontario customers and not just those of the specific LDC).

B. ALTERNATIVE RATE DESIGNS

1. EV FLEET CHARGING

1.1. TO WHAT EXTENT ARE THE PROPOSED ALTERNATIVE RATE DESIGN OPTIONS EFFECTIVE SOLUTIONS FOR THE CHALLENGES IDENTIFIED?

As noted in the Report the challenges that commercial EV fleets experience with demand charges vary due to the heterogeneity of fleets themselves in terms of both charging patterns and fleet sizes[39]. To this end, it is important to note the following statement in the Report:

"This report focuses on commercial EVs with a predictable overnight charging pattern that have some flexibility in the timing of their charging demand. Not all commercial vehicles meet this description. There are many different usage patterns, and some commercial EVs would be unable to adjust their charging demand to take advantage of an alternative rate design." (page 54)

An example of the variation in current load profiles is the fact that the transit bus profile used in the Report "was assumed to have sufficient flexibility to shift demand in hours ending 19 through 21 to later in the overnight period"[40]. Whereas, during the Stakeholder meeting, a representative from the TTC noted that their EV charging requirements included the need for mid-day charging.

[39] Page 47
[40] Page 55

Furthermore, the bill saving calculations assumed that the Commercial EV Fleet customers would be able to shift a portion of their current peak period usage to the off-peak period and incorporated such shifts in the Report's analysis.[41]

In addition, the cost of demand charges for commercial EV fleets vary significantly depending on the customer's LDC and the choice of the peak period hours will need to reflect system/LDC needs. The report uses a fairly broad peak period from hour ending 8 to hour ending 21 every day. The breadth of the peak period may impair the ability of some EV Fleet Customers to shift their load to the off-peak, thereby reducing the effectiveness of the TOU Demand Charge as solution to the higher delivery charges they currently face.

As result, it can be expected that the effectiveness of the proposed TOU Demand Charges will vary and, in some case, may not provide much (if any) relief from current electricity delivery charges.

1.2. TO WHAT DEGREE DOES THE COST ALLOCATION PROPOSED IN THE EXAMPLE CONSTRUCTIONS OF EACH RATE (SECTION 4.1 IN REPORT) REFLECT COST CAUSATION OF THE COSTS IMPOSED BY EV CONSUMERS?

For purposes of determining the TOU Demand Charge the Report divides demand-related delivery costs between those that are related to coincident peak (CP) demand and those that are related to non-coincident peak (NCP) demand. The Report includes in CP related demand costs 100% of RTSRs plus the CP-related distribution costs (per the OEB's Cost Allocation Model).[42]

RTSR CP Costs

With respect to the RTSRs it is noted that only the RTSR-Network charge is actually billed using CP demand, where the CP demand is based on customer's coincident peak demand (MW) at the Transmission Delivery Point in the hour of the month when the total hourly demand of all Provincial Transmission Service customers is highest for the month. However, even then, this is only the case when this value is higher than 85% of the customer peak demand in any hour during the peak period defined as weekdays (excluding the holidays as defined by IESO) between the 0700 hours to 1900 hours Eastern Standard Time during winter (i.e., during standard time) and 0600 hours to 1800 hours Eastern Standard Time during summer (i.e., during daylight savings time) at the Transmission Delivery Point[43].

In the case of RTSR-Line Connection and RTSR-Transformation Connection charges the billing determinant is based on the Non-Coincident Peak demand (MW) in any hour of the month at the Transmission Delivery Point[44].

It is important to note that many LDCs have more than one Transmission Delivery Point and that the timing of NCP demand could be different at each. As a result, the relevant

[41] Page 54. Also confirmed during the May 24th Stakeholder meeting.
[42] Page 25
[43] 2023 UNIFORM TRANSMISSION RATES: EB-2022-0250.
[44] 2023 UNIFORM TRANSMISSION RATES: EB-2022-0250

coincident peaks for purposes of determining CP-related RTSR costs (as interpreted in the Report) is not Ontario's system peak nor the LDC's system peak but rather a combination of the Ontario system peak and the NCP peaks at each of the LDC's Transmission Delivery Points.

The explicit assumption in the construction of the TOU Demand Charge is that the Ontario system peak and all of the Transmission Delivery Point NCPs will occur within the peak period established for purposes of the rate. For the proposed treatment to align with the principle of cost causality, this assumption would need to be confirmed for each individual LDC implementing the rate and periodically reconfirmed going forward. This issue becomes more problematic if a common peak period definition is to be used for all LDCs unless the peak period is extremely large. However, as noted above, the broader the peak period the more difficult it will be for Commercial EV Fleet customers to shift their loads outside the peak period.

While the actual monthly RTSR charges are assumed to the demand related, the proposed construction for the TOU Demand Charge considers the rate riders used to refund/recover the balances in the associated variance accounts (1584 and 1586) to be NCP related[45]. This may be appropriate as these balances are allocated to customer classes based kWh usage. However, the overall treatment of rate riders currently billed on an NCP demand basis needs to be further considered before a TOU Demand Charge is implemented.

Distribution CP Costs

As noted in the Report:

> *"The OEB's Cost Allocation Model for Electricity Distributors classifies a share of an LDC's assets and costs as demand-related, which is further subclassified between CP demand and NCP demand. Land, Land Rights, Buildings and Fixtures, Leasehold Improvements, Transformer Station Equipment, and Storage Battery Equipment are classified to CP-related demand. Shares of other distribution plant sub-functionalized to serving loads above 50 kV are also classified as CP-related demand. The allocation of demand-related assets is an input in the calculation of the composite allocators used to allocate general plant and some operations, maintenance, and administration (OM&A) accounts."* (page 25)

In the OEB's Cost Allocation model, CP-related demand costs are allocated based on each customer class' contribution to the LDC's monthly system peak demand[46]. The timing of this peak may or may not coincide with that of the Ontario system peak or with those for the LDCs individual Transmission Delivery Points. Again, the assumption that the LDC's overall system peak occurs within the peak period established for purposes of the rate would also need to be tested and periodically confirmed.

---

[45] During the May 24th Stakeholder meeting it was confirmed that these riders were included as "Other NCP Charges" per Table 8 in the Report.

[46] The CP allocation factor used can be based on either the single month with the highest peak, the four months with the highest peaks or all 12 months depending on the LDC's load profile.

Another issue is the fact that the OEB's Cost Allocation Model classifies all Land, Land Rights, Buildings and Fixtures and Leasehold Improvements as CP-demand related. This is appropriate for land and building associated with Distribution Stations and Transformation Stations (where owned by the LDC) since these facilities are allocated on a CP-demand basis. However, it is not appropriate for land associated with administrative buildings or service yards as in both cases the purpose is to support the LDC's total operations and not just facilities whose costs are allocated on the basis of CP demand.

Finally, LDCs typically only undertake a Cost Allocation Study when they are rebasing their rates and filing a full Cost of Service Application. While LDCs are meant to rebase every five years, this is not always case. Instances where the last Cost Allocation is older would include: i) LDCs that are the result of past mergers/amalgamations and are therefore eligible for the 10 year deferral period and ii) LDCs that are on Annual IRM. For these LDCs a question arises as to how many years can pass before the last Cost Allocation Study is too old for purposes of determining the portion of Distribution costs that are CP demand related. This question can also arise for those utilities that have installed their own transformation facilities since the last Cost Allocation Study which will lead to a reduction in RTSR rates but an increase in the Distribution costs that are CP demand related.

TOU Period

As noted in the Report[47]:

> *"There are trade-offs when selecting the length of the daily peak period. The timing of CP is uncertain. It may vary from year to year and between geographic areas. A longer peak period would increase the likelihood of including the CP. A longer peak period would also limit the number of customers that would be able to avoid peak period demand charges, reducing the impact of the rate on other customers. To be useful for commercial EV fleets, the off-peak period would need to be sufficiently long to charge the fleet and occur during hours when vehicles are not in use. Finally, a peak period could be defined every day or only on a subset of days such as non-holiday weekdays. This analysis uses a peak period from hour ending 8 to hour ending 21 every day.*

As noted above, the Report uses a fairly broad peak period which is likely to capture the range of CP values discussed above for most (if not all) LDCs.

Low Voltage Charges

Some LDCs are fully or partially "embedded" within another LDC and, as such, are charged a rate by their host distributor designed to recover the distribution costs incurred by the host. In such cases the delivery rates charged to the embedded distributor's customers also include a Low Voltage Service Rate to recover these charges from the host. The Report does not acknowledge or discuss the treatment of the Low Voltage Service charges. However, GS>50 customers are typically billed for these charges using a monthly service charge plus an NCP demand charge. As a result, consideration should be given to treating these charges as CP demand-related.

[47] Page 24

Incentive to Shift Load

The TOU Demand Charge provides a very real incentive for Commercial EV Fleet customers to shift their charging load to the off-peak period. As a result, properly constructed the rate will not only reflect cost causation but can also lead to more efficient use of the Transmission and Distribution delivery systems.

1.3. DOES THE PROPOSED COST ALLOCATION JUSTIFY THE POTENTIAL INCREASE IN THE COST TO OTHER NON-EV CONSUMERS?

If the TOU Demand Charge is cost based (particularly if it is more reflective of costs than the current GS>50 rate) and implemented on a non-discriminatory basis then there should be no issue with respect to cross-subsidization and the question is one of bill impacts due to implementation (not fairness). In this, the issue is similar to that which occurs when customer class revenue to cost ratios fall above the Board's "policy ranges" and the adjustments proposed will result in an increase in costs/rates to other customer classes.

In the case of the TOU Demand Charge, the Report estimates that by 2035 Commercial EV Fleet customers will represent 1.8% of the NCP demand in the GS>50 class and if this load avoids the peak period there would be a 0.2% to 0.3% electricity bill impact on the other customers in the GS>50 class. Looked at in this context the bill impact seems small (and manageable) given that it will take place gradually over roughly 10 years and occurs only if all of the Commercial EV Fleet customer load avoids the peak.

However, there are several of reasons for caution:

- First the 1.8% is based on the Commercial EV Fleet customers' forecast share of energy in 2035. If the load factor for Commercial EV Fleet customers is lower than the GS>50 class' average load factor then the impact on NCP billing demand will be greater than 1.8%.
- Second, the concentration of Commercial EV Customers is likely to vary across LDCs leading to higher bill impacts in some LDCs.
- Third, if the rate is made available on a wider basis to all GS>50 customers then clearly the amount of load avoiding the peak period demand charge will increase with a resulting increase in the overall bill impact for other GS>50 customers.

1.4. IMPLEMENTATION ISSUES/CONSIDERATIONS

Apart from the implementation issues specifically noted in Section C (below) there are several implementation issues that are specific to the TOU Demand Charge. Those already noted in the previous discussion include:

- The need to clarify the principle used to determine CP demand related costs. More specifically, do they include: i) only Transmitter and Other Distributor costs billed to the utility and LDC distribution costs allocated to its customers on a CP demand basis or ii) does it also include those Transmitter and Other Distributor costs where the NCP billing demand is expected to occur in the "peak period" (as done in the Report).
- The need to review the CP allocation of all Land, Land Rights, Buildings and Fixtures and Leasehold Improvements in the OEB's Cost Allocation Model.

- The need to determine the CP/NCP treatment for the various rates riders used by LDCs.
- The need to determine the CP/NCP Treatment of Low Voltage Charges

Other implementation issues associated with the TOU Demand Charge include:

- Should the determination of the TOU peak period consider not only the timing of the current Ontario system peak, LDC system peak and NCP billing demands at the various Transmission (and Host Distributor) Delivery Points but also the potential impact of load shifting on that timing.
- The Report shows the CP-demand related costs all combined into one demand charge. However, it will be necessary to separately identify the revenues deemed to be related to the RTSR-Network, RTSR Connection and LV Charge portions of the overall demand charge as these need to be tracked/recorded in separate variance accounts.
- While the OEB's Cost Allocation Model can be used to determine the dollar values for the costs allocated to the GS>50 class on the basis of CP-demand, these are not directly translatable into their contribution to the CP demand charge. The reasons for this are two-fold. First, the revenue to cost ratios for most (if not all) GS>50 customer classes in Ontario's LDC do not equal 100%. Second, the percentage of costs allocated to the GS>50 class using demand is not necessarily equal to the percentage of GS>50 class revenues collected via demand charges. As a result, it will be necessary to establish a methodology for determining the contribution of CP demand-related distribution costs to the CP demand charge.

2. <u>PUBLIC EV CHARGING</u>
   2.1. <u>TO WHAT EXTENT ARE THE PROPOSED ALTERNATIVE RATE DESIGN OPTIONS EFFECTIVE SOLUTIONS FOR THE CHALLENGES IDENTIFIED?</u>

The proposed Low Load Factor rate provides a direct solution to the high per kWh delivery charge challenge faced by low load factor customers. At the same time, it does not provide any incentive to shift load to the off-peak peak period. However, this may not be a major deficiency since the Public DCFCs customers are not the actual users and the actual users (EV vehicle drivers on extended journeys) are unlikely to be interested in changing the timing of their charging requirements.

Another concern with the proposed rate design is that for customers with load factors slightly higher than 15% the cost per kWh actually increases when customers are transitioning back to the regular GS>50 rate and does not fall to the same/lower value until the load factor is somewhere over 19%[48]. If, as the Report suggests[49], Public DCFC customers will consider adding ports to an existing station when the load factor reaches 18% to reduce the risk of queues then the current construction may encourage them to do so even sooner leading to a less efficient use of public DCFCs. However, other sources suggest that maximum utilization levels will be much higher. For example a DCFC Rate Design Study undertaken for the Colorado Energy Office suggests that 30% represents the utilization rate that a public DCFC might experience in a mature EV

[48] See Report Figure 14
[49] Page 28

market[50]. If maximum utilization rates are expected to be significantly higher than 15% then the current rate construction will not overly inhibit DCFCs customers targeting such levels. However, if the maximum expected utilization rates are closer to 18% then the proposed construction could be sending perverse pricing signals.

2.2. TO WHAT DEGREE DOES THE COST ALLOCATION PROPOSED IN THE EXAMPLE CONSTRUCTIONS OF EACH RATE (SECTION 4.1 IN REPORT) REFLECT COST CAUSATION OF THE COSTS IMPOSED BY EV CONSUMERS?

Similar to the TOU Demand Rate, for purposes of constructing the Low Load Factor Rate, the Report divides demand-related delivery costs between those that are related to coincident peak (CP) demand and those that are related to non-coincident peak (NCP) demand. The Report includes in CP related demand costs 100% of RTSR plus the CP-related distribution costs (per the OEB's Cost Allocation Model). It is this portion of delivery demand charges that the Report applies the CPC (Coincident Peak Contribution) factor(s) to for purposes of determining the Low Load Factor Rate Options 2a and 2b.[51]

CP-Related Demand Costs

Section 2.1 identified a number of issues[52] related to establishing CP-related demand costs, these same issues apply with respect to the construction of the Low Load Factor Rate.

Determination of the CPC Factor

For purposes of constructing the Low Load Factor rates the Report assumes that: i) a Public DCFCs customer's load factor is equal to its utilization factor[53] and ii) there is a linear relationship between load factor and likelihood of contributing to CP demand. Both of these assumptions are overly simplistic and incorrect.

For the load factor to equal the utilization factor the load at a Public DCFC would have to be zero when no charging was taking place and at 100% of the charging ports peak capability when a charging port was in use[54]. However, neither of these premises are correct. Public DCFCs are likely to have lighting and other ancillary equipment that are in use even when the charging ports are not being used. Also, the Report itself states that when Public DCFCs are in use:

> *"The NCP demand of an EV charging station is not necessarily its total rated charging power. Power levels fluctuate during a charging session and seldom reach the full rated power. In addition, multi-port stations with low utilization are unlikely to have all ports in use at full power simultaneously*". (page 56)

---

[50] DCFC Rate Design Study For The Colorado Energy Office (2019), retrieved from https://rmi.org/insight/dcfc-rate-design-study/, page 12

[51] Pages 27-28

[52] See the sub-sections dealing with i) RTSR CP Costs, ii) Distribution CP Costs and iii) Low Voltage Charges

[53] Page 1

[54] It is possible for the load factor to equal the utilization factor when these conditions are not met but highly unlikely

With respect to the relationship between load factor and coincidence factor, it is widely accepted that for a class of customers the likelihood of an individual customer's peak being coincident with the customer class peak increases as the customer's load factor increases. As noted in the Report[55] it is the principle underpinning Hydro Quebec's proposed Rate BR. It has also been used by other utilities such as SaskPower, Newfoundland Power and the former Ontario Hydro in the design of rates. However, as indicated by the quote from Hydro Quebec's proposed BR rate application[56] the coincidence factor is not typically equal to but higher than the load factor (with two intersecting at 100%). Indeed this was the relationship found by Ontario Hydro in its load research. This suggests that the CPC factors used in the Report to construct the rates for Options 2a) and 2b) are likely too low.

Also, as noted above in the discussion regarding the construction of the TOU Demand Charge, RTSR-Network, RTSR-Connection and CP-related Distribution costs each use a different definition of demand for purposes of billing/allocating the associated costs. As a result, there are likely to be at least three different and relevant customer demand vs. CP demand relationships to consider when establishing the CPC factor (and even more if there is more than one Transmission Delivery Point). Furthermore, since GS>50 class customer characteristics vary by LDC, these relationships will be different for each LDC. To ensure the construction of the Low Load Factor Rate reflects cost causality will require each LDC to undertake the necessary load research to determine these relationships.

At the same time, one limiting factor in the construction of the Low Load Factor rate is that there is likely limited actual Ontario data on the load profiles for Public DCFCs and, indeed, some LDCs may not have any such stations. As a result, there will likely be insufficient data (as least in the initial years) to properly estimate the appropriate CPC factors.

Use of 24x7 Load Factor

The load factor used in the determination of the CPC factors and the customer segmentation in Options 2b) and 2c) is based on a Public DCFCs' usage over the entire year[57]. However, as the Report notes "because the load profile for EV charging stations is more concentrated in the daytime than other loads, a higher CPC for a given load factor may be appropriate"[58]. One way to address this would be to use the customer's peak period load factor and base the CPC factor on the relationship between this load factor and the various CP values used for billing/allocating CP demand costs.

Option 2 b) – Tiered Demand Rates

The Report does not provide any cost-based rationale for the use of three tiers (as opposed to a different number of tiers) or the selection of the tier thresholds. Indeed, the Report acknowledges that selection of the tiers and thresholds would require further

[55] Page 26

[56] Report, page 26. If the coincidence factor decreases rapidly when the load factor fall below 30%, this implies the coincidence factor associated with a 30% load factor is higher than 30%.

[57] This was confirmed during the May 24th Stakeholder meeting

[58] Page 28, Footnote #33

analysis and consultation. In this regard, VECC notes the same load research required to establish the CPC factor(s) can also be used to determine the appropriate number of tiers and their thresholds.

Options 2c) – Inclusion of an Energy Charge

The Report notes that for Option 2c):

- CPC for Option 2c) is arbitrarily set to be 0.04 lower than Option 2b, with the difference recovered using a small energy-based charge[59].
- The TOU energy charge in Option 2c) was modelled using the same time periods as the winter 2022-2023 Regulated Price Plan (RPP) TOU rates. The RPP TOU rates are multiplied by a scaling factor for the five Load Factor bins in Table 9[60].

The Report provides no explanation or cost-based rationale for reducing the CPC factor by 0.04. Again, the same load research used to establish the CPC factor should be able help establish a cost basis for the energy charge.

Also, it is not at all clear why the TOU energy charge should use the same time periods and be prorated between time periods based the RPP TOU rates. RPP time periods and period rate differentials are based on the time profile for generation costs – not delivery costs.

2.3. DOES THE PROPOSED COST ALLOCATION JUSTIFY THE POTENTIAL INCREASE IN THE COST TO OTHER NON-EV CONSUMERS?

Similar to the TOU Demand Charge, if the Low Load Factor Rate is cost based (particularly if it is more reflective of costs than the current GS>50 rate) and implemented on a non-discriminatory basis then there should be no issue with respect to cross-subsidization and the question is one of bill impacts due to implementation (not fairness). Again, the issue will be similar to that which occurs when customer class revenue to cost ratios fall above the Board's policy ranges and the adjustments proposed will result in an increase in costs/rates to other customer classes.

In the case of the Low Load Factor Rate, the Report estimates that by 2035 Public DCFCS customers will represent 3.4% of the NCP demand in the GS>50 class and assuming a 10% utilization factor implementation of Option 2a) would result in a bill impact of 1.7% to 2.8% on the other customers in the GS>50 class. Looked at in this context the bill impact again seems small (and manageable) given that it takes place gradually over roughly 10 years and occurs only if all of the Public DCFCs customers opt for the rate.

Again, however, there are several reasons for caution:

- First the 3.4% is based on the Public DCFCs customers' forecast share of energy in 2035. If the load factor for Public DCFCs customers is lower than the GS>50 class' average load factor then the impact on NCP billing demand will be greater than 1.8%.
- Second, the concentration of Public DCFCs customers is likely to vary across LDCs leading to higher bill impact in some LDCs.

---

[59] Page 28

[60] Page 29

- Third, if the rate is made available on a wider basis to all GS>50 customers then clearly the amount of load on the Low Load Factor Rate will increase with a resulting increase in the overall bill impact for other GS>50 customers.

2.4. IMPLEMENTATION ISSUES/CONSIDERATIONS

Apart from the implementation issues specifically noted in Section C (below) there are several Low Load Factor Rate implementation issues that are either: i) common with those for the TOU Demand Charge or ii) specific to the Low Load Factor Rate.

Those that are common to both the TOU Demand Charge and the Low Load Factor Rates include:

- The need to clarify the principle used to determine CP demand related costs. Specifically, do they include: i) only Transmitter and Other Distributor costs billed to the utility and LDC distribution costs allocated to its customers on a CP demand basis or ii) does it also include those Transmitter and Other Distributor costs where the NCP billing demand is expected to occur in the "peak period" (as done in the Report)?
- The need to review the CP allocation of all Land, Land Rights, Buildings and Fixtures and Leasehold Improvements in the OEB's Cost Allocation Model.
- The need to determine the CP/NCP treatment for the various rates riders used by LDCs.
- The need to determine the CP/NCP Treatment of Low Voltage Charges
- The Report shows the CP-demand related costs all combined into one demand charge. However, it will be necessary to separately identify the revenues deemed to be related to the RTSR-Network, RTSR Connection and LV Charge portions of the overall demand charge as these need to be tracked in separate variance accounts.
- While the OEB's Cost Allocation Model can be used to determine the dollar values for the costs allocated to the GS>50 class on the basis of CP-demand, these are not directly translatable into their contribution to the CP demand charge. The reasons for this are two-fold. First, the revenue to cost ratios for most (if not all) GS>50 customer classes in Ontario's LDC do not equal 100%. Second, the percentage of costs allocated to the GS>50 class using demand is not necessarily equal to the percentage of GS>50 class revenues collected via demand charges. As a result, it will be necessary to establish a methodology for determining the contribution of CP demand-related costs to the CP demand charge.

Implementation issues specific to the Low Load Factor Rate include:

- For LDCs implementing the Options 2a) or 2 b) rate, there will be a need for additional load research to establish the relevant CPC factor(s) for their utility. In the case of Option 2b) additional load research will also be required to determine the appropriate tiers and thresholds.
- Options 2 b) and 2c) both involve the development of load factor tiers and thresholds and procedures will be required for doing so. Also, since a customer's load factor can vary from month to month, rules/procedures will be required to establish the basis on which Low Load Factor Rate customers are assigned to the tiers (e.g. does tier assignment change every month based on load factor or less frequently based

on historical load factors and, if the later, what how is this determination made and how frequently should it be reassessed?).

- To assist LDCs in the implementation of Option 2c), direction is required on how LDCs should determine the portion of the demand charge to be collected through energy rates, the appropriate TOU period to use and how the energy costs should be pro-rated across the TOU periods.

3. ARE THERE OTHER ALTERNATIVE RATE DESIGN OPTIONS, NOT CONSIDERED IN THE REPORT, THAT THE OEB SHOULD CONSIDER?

CP-Billing

During the May 24th Stakeholder meeting the issue of Coincident Peak (CP) billing was raised (i.e., where the demand billing determinant is the customer's coincident demand). This approach was considered in the Report and rejected:

> *"A CP demand charge was ruled out because, as noted in the previous paragraph with respect to TOU and critical peak pricing, this option would likely be challenging for customers who would have to manage peaks for both the delivery and commodity portions of the bill (which may not have aligned), and because it is unclear what CP demand charges should be coincident to, e.g., to a local feeder peak, the LDC's overall peak, total provincial system peak, etc. Finally, this option would also introduce significant complexity for LDCs."* (page 65)

VECC agrees with the Report's comments and does not consider CP billing to be an appropriate solution to the delivery cost challenges faced by either Commercial EV Fleets or Public DCFCs.

Low Load Factor Rates Based on Peak Period Load Factor

As noted in Section 2.3 one of the issues with the current construction of the Low Load Factor rate is that the load factor used reflects a customer's usage over all hours. This means that customers with load factors are treated the same whether their usage is in the peak or off-peak period. However, the likelihood that a customer's peak will contribute to a System, Utility or Transmission Delivery Point peak will be higher if usage (although at a low load factor) is concentrated in the peak period. To address this issue, the OEB could consider a variation of the Low Load Factor Rate that uses the relationship between a customer's load factor as measured in the peak period hours only and the relevant CP-demand.

C. IMPLEMENTATION OF ALTERNATIVE RATES

1. FORMAT AND PROCESS

1.1. TO WHAT EXTENT SHOULD THE DESIGN OF THE RATES BE CONSISTENT ACROSS LDCS (BASED ON THE SAME COST ALLOCATION METHODOLOGY, BILLING DETERMINANTS, AND TOU TIME PERIODS AS APPROPRIATE)?

To the extent practical, the design of the rates should be consistent across LDCs. This would include: i) Using the OEB's Cost Allocation Methodology to determine CP-demand related Distribution Costs; ii) Using the same billing determinants; iii) Using the same load factor definition (e.g., 7x24); iii) Using the same load research approach to determine the CPC factors, tiers and thresholds required for the Low Load Factor Rate.

However, there are differences between LDCs that will need to be recognized in the design of the rates:

- The timing of Utility and individual Transmission Delivery Point monthly peaks will vary and it is important that the peak period used by an LDC captures the timing of its relevant peak demands. As noted above establishing a common peak period that addresses this issue for all LDCs may result in a peak period that includes so many hours that Commercial EV Fleet customers are unable to shift their load off-peak. This may necessitate the use of LDC-specific TOU periods. If this is the case, there should be a common methodology/approach for determining the appropriate periods.
- The average GS>50 class customer load factor and the CPC values will vary by LDC and the design needs to allow for this variation. However, there should be common methodologies/approaches for determining both: i) the average load factor for the GS>50 class and ii) the CPC factors from LDC specific load research.
- While there should be a common methodology/approach for determining the tiers and thresholds associated with Low Load Factor Rate Options 2b) and 2c), it is not clear whether there will be sufficient similarity in the results to allow the Board to establish a common set of tiers/thresholds for all LDCs.
- While off-peak load may have minimal impacts on the facilities that deliver power to an LDC or major distribution facilities such as distribution stations supporting multiple feeders, off-peak load may be a critical consideration with respect to individual feeders particularly if EV charging becomes more widespread.

1.2. SHOULD IMPLEMENTATION OF ALTERNATIVE EV DELIVERY RATES BE OPTIONAL OR MANDATORY FOR INDIVIDUAL LDCS?

Ideally such rates would be mandatory for all LDCs. The reasoning being that customers considering either the use of an EV Fleet or the installation of DCFCs in a particular LDC's service territory will want to know the rates they will be paying for electricity. As the alternative EV delivery rates can vary significantly across individual LDCs[61], it will be important that LDCs have established the rates applicable to their circumstances.

However, there may be instances where the LDC's currently available GS>50 load data is not sufficiently robust to establish the parameters for the Low Load Factor Rate. In these instances the Board may need to allow extra time for such data to become available. Alternatively, the Board could direct the LDC to use proxy data. However, the latter approach could create future issues if, when the data does become available, the use of the LDC's actual GS>50 load data leads to a material increase in the Low Load Factor Rate.

[61] For an illustration of this see Table 12 in the Report

1.3. SHOULD ALTERNATIVE DELIVERY RATES BE INTRODUCED AS A NEW RATE CLASS, WITHIN EXISTING RATE CLASSES (E.G., VIA A NEW OUTPUT WORKSHEET IN THE COST ALLOCATION MODEL) OR USING ANOTHER METHOD?

The alternative delivery rates should be introduced as additional rate available to GS>50 customers as opposed to a new rate class. In coming to this view VECC considered the following:

- First, implementing the alternative delivery rates as separate rate classes would require the creation of two classes: one for Commercial EV Fleet customers and another for Public DCFCs customers. The reason for this is that the two have materially different profiles and hence the cost allocation results (e.g. dollars allocated per kWh) would be different for each.
- Also, for many LDCs, initially there are likely to be a limited number of customers in each of the classes or maybe none at all. As a result, the data required to determine the load characteristics of the new classes for purposes of the OEB's Cost Allocation model may be limited/unavailable. Furthermore, the load characteristics of the class, particularly the Low Load Factor Rate class, could change materially as the number of customers increases. The bass for this last point is explained further in the Report itself[62].
- Finally, implementing the alternative delivery rates using new rate classes would impact the costs allocated to all other classes on an NCP basis.

2. CONSUMER OPTIONALITY

2.1. SHOULD THE ALTERNATIVE RATES BE OPTIONAL OR MANDATORY FOR THE TARGETED EV CONSUMERS?

In VECC's view there are two considerations involved in addressing this question. From a cost causality perspective, to the extent the alternative delivery rates better reflect the cost of providing delivery service, this would suggest that the rates be mandatory for all Commercial EV Fleet and Public DCFCs customers. However, from a customer understandability and acceptability perspective, the preferred approach would be that the rates be optional. VECC notes that the genesis for these rates was to "address the delivery costs challenges" faced by these types of EV charging customers. Such customers are likely to find themselves in a variety of circumstances and, in some instances, the proposed rates may not improve the economics of EV charging sufficiently to make them attractive to customers. For example, this could be the case for the Low Load Factor rate if the Public DCFCs customer has other facilities at the same location[63], expects to exceed the 15% threshold in short period of time and separate metering requirements[64] are necessary to access the alternative delivery rate.

[62] Page 27

[63] For example, a restaurant, store and/or standard gas station

[64] Separate metering requirements trigger not only the cost of an additional meter but may also require the customer to pay for re-wiring of the way electricity is supplied and additional ongoing billing costs.

Overall, VECC submits that the rates should be optional, particularly the Low Load Factor Rate which is expected to be a transitional rate that the customers will only be on for a limited period of time.

2.2. WHAT ARE THE RISKS/OPPORTUNITIES OF OFFERING CUSTOMER CHOICE IN DELIVERY RATES SIMILAR TO THE CHOICE OF PRICE PLANS THAT CURRENTLY EXISTS WITHIN THE REGULATED PRICE PLAN?

The preceding section touches on some of the risks/opportunities associated with offering Commercial Fleet and Public DCFCs customers choice when it comes to delivery rates. In addition, offering customers choice is likely to lead to revenue instability as forecasts regarding the number of customers adopting the alternative delivery rates will become less reliable. However, given the fact the kWh involved are likely to represent only a small portion of the GS>50 load[65], the overall risk is likely minimal.

Also, offering customers choice necessitates the development of rules regarding when and how frequently customers can opt-in/opt-out. Such rules would have to balance customers' desire for choice with the need for LDCs to manage the opt-in/opt-out process and maintain the integrity of the alternative delivery rates (e.g., prevent customers from "gaming" the process).

3. ELIGIBILITY

3.1. SHOULD THE ALTERNATIVE RATE(S) BE OFFERED TO EV CHARGING CONSUMERS FOR EV CHARGING LOAD EXCLUSIVELY?

In principle a customer's eligibility for a rate option should not be based on the use to which the electricity is being put. Rather eligibility should be based on the customer's load and service characteristics such that customers with similar characteristics pay similar rates. Indeed this is the premise behind Bonbright's fairness principle[66]. This perspective also aligns with the legislative requirement that the OEB approve rates that are "just and reasonable".

As result, it is VECC's view that, as a matter of principle, the alternative rates should not be limited to EV charging consumers for EV charging load exclusively.

The primary exception to this principle would be where the Government, through legislation/regulation, has directed the OEB to do so. However, in VECC's view, a Ministerial direction to "consider distribution rates for EV charging" does not meet this threshold.

[65] See Report, pages 38 and 41
[66] Report, page 66

3.2. TO WHAT DEGREE SHOULD THE ALTERNATIVE RATE(S) BE OFFERED TO ANY CUSTOMER HAVING DEFINED LOAD CHARACTERISTICS (E.G., LOW LOAD FACTOR)?

TOU Demand Charge

The construction of the TOU Demand Charge is not based on the load characteristics of the customers that will use it. As a result, there is no need to limit the rate to customers with defined set of load characteristics and could be open to all customers.

As VECC understands the proposed construction of the rate the current $/kW delivery charges are broken down into two components: i) that portion of the $/kW that is associated with cost driven by customers' peak period load (i.e., RTSRs, LV Delivery Charges and CP-demand related Distribution Costs) and ii) that portion of the $/kW that is associated with NCP demand. The $/kW attributed to CP demand is then marked up (for both the TOU Demand Charge and its contribution to the standard GS>50 demand charge) to address any revenue loss from applying the rate to the customer's peak period demand as opposed to the customer NCP demand for those customers on the TOU Demand Rate. As a result, if more customers are offered and take up the rate this adjustment will need to increase.

Also, wider availability of the rate would likely lead to more shifting of existing load to the off-peak period such that the timing of the LDC's utility and delivery point peaks may be altered and the need arise to re-define (widen) the peak period definition. Such a move would likely impact customers already on the rate including those EV charging customers the rate was originally intended to benefit. As result, careful and further consideration would be required before opening this rate up to all potential users.

Low Load Factor Rate

The construction of the Low Load Factor Rate does draw heavily on the load characteristics of the participating customers as those characteristics define the CPC factor used to derive the demand charge. As result, if the Low Load Factor Rate was made available to other (non-EV charging) customers it would have to be limited to customers with similar characteristics. Further work would be required to define what those characteristics and the associated eligibility criteria should be.

3.3. +ARE THERE OTHER SPECIFIC CONSUMER TYPES WHO SHOULD BE ELIGIBLE FOR THE ALTERNATIVE RATE(S)?

VECC'S views on this question have been provided in Section 3.2.

3.4. WHAT ARE THE RISKS/OPPORTUNITIES OF OFFERING THE ALTERNATIVE RATE(S) TO ALL CONSUMERS ON AN OPTIONAL BASIS?

If VECC's understanding as to the proposed construction of the TOU Demand Charge is correct[67], then GS>50 customers whose NCP demand occurs in the peak period will be billed the same amount whether they are billed using the TOU Demand Charge or the Standard GS>50 rates. As a result, there would no downside to choosing the TOU Demand Charge regardless of the customer's load profile. At the same time, there would be an upside any time the customer's peak demand occurred in the off-peak period. As customers come to this realization the number opting for the TOU Demand Charge could increase substantially and, over time, it could become the defacto GS>50 rate.

One way to avoid the decline of the Standard GS>50 rate would be to increase the TOU Demand Charge's peak period rate. If this approach was pursued then further work would be required to determine the appropriate TOU rate. Alternatively, eligibility criteria could be established for the TOU Demand Charge such that it was only available to customers whose off-peak demand exceeded their peak demand. However, this approach would require the development of eligibility requirements. Also, issues would arise if their application resulted in customers being shifted on a regular basis from one rate to the other.

As noted in Section 3.2, the construction of the Low Load Factor Rate is driven by the load characteristics of the customers using the rate. Offering it to a wider range of customers is likely to change the actual rate. Also, if the characteristics of those customers on the rate change the rate would have to be re-constructed accordingly.

4. METERING

4.1. IF REQUIRED, WILL THE COST OF SEPARATE METERING FOR EV CHARGING (OR OTHER APPROVED MEANS OF MEASURING CONSUMPTION) OUTWEIGH THE BENEFITS OF THE ALTERNATIVE RATE(S)?

Need for Separate Metering

In the case of the TOU Demand Charge there is no need for separate metering unless the rate is to be limited specifically to EV Charging facilities.

In the case of the Low Load Factor Rate, without specific metering of the just the DCFCs (or other loads if made more broadly available) the load factor of the metered load may not qualify for the rate. Furthermore, the CPC factors used to determine the rate will include loads not associated with EV charging.

Cost/Benefit Implications of Separate Metering

While meter costs may be fairly standard the changes/rewiring required to accommodate separate metering will likely vary widely by customer as will the

[67] Both the peak period demand charge for the TOU Demand Charge and the NCP demand charge for the standard GS>50 rate are increase by the same amount in order to maintain revenue neutrality – see Section 3.2 above.

associated costs. As a result, the extent to which the overall costs of separate metering outweigh the benefits (which again will be circumstance specific depending on the customers load characteristics and the LDC's alternative EV delivery rates) can be expected to vary widely by customer and LDC.

D. CONCLUSIONS

The two rate options identified by Power Advisory show promise in being able to address the delivery cost challenge faced by some EV Fleet and Public DCFCs customers consistent with the principles of cost causality and improving the efficient use of Ontario's electricity transmission and distribution system. However, as noted throughout the preceding comments and in the Power Advisory Report itself[68] , additional work is still required to further determine the reasonableness of these options and how best to implement them should the Board decide to further consider them.

[68] Page 49