Ontario Energy Board | Commission de l'énergie de l'Ontario

BY EMAIL

October 30, 2024

Ms. Nancy Marconi
Registrar
Ontario Energy Board
2300 Yonge Street, 27th Floor
Toronto, ON M4P 1E4
Registrar@oeb.ca

Dear Ms. Marconi:

Re: Generic Hearing on Uniform Transmission Rates – Phase 2
OEB File Number: EB-2022-0325

Please find attached OEB staff's reply submission in the above referenced proceeding, pursuant to Procedural Order No. 4.

Yours truly,

Thomas Eminowicz
Digitally signed by Thomas Eminowicz
Date: 2024.10.30 14:58:18 -04'00'

Thomas Eminowicz

Senior Advisor, Generation & Transmission

Encl.

cc: All parties in EB-2022-0325

ONTARIO ENERGY BOARD

OEB Staff Reply Submission

Generic Hearing on Uniform Transmission Rates
Phase 2

EB-2022-0325

October 30, 2024

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Summary of OEB's Staff's Position on the Issues

On October 16, 2024, in accordance with Procedural Order No. 4, several participants, along with OEB staff, filed submissions on Issue 4, 5, and 6. The following is a summary of OEB staff's positions, which are consistent with OEB staff's October 16, 2024 submission, on Issues 4, 5, and 6:

Table 1: OEB staff's position on each of the Issues

Issue	OEB Staff Position
Issue 4.1: Should all transmission charges (Network, Line connection, Transformation Connection) continue to be on a per delivery point basis, whereby the customer's charges would be calculated separately for each delivery point, or should they instead be calculated on an aggregate per customer basis, whereby the transmission charges would be calculated on the customer's aggregate demand for all delivery points for a given time interval?	Network Service Charge: Transmission customers should have the option to aggregate their delivery points Line and Transformation Connection Charges: Transmission Customers should be billed by delivery point
Issue 4.2: Should the measures to address the impact of double-peak billing be applied to both planned and unplanned transmission outages or should there be separate measures? What should be the objectives of those measures?	Transmission outage charges should not receive special treatment. The primary objective should be cost causality. Billing should reflect the usage of the particular transmission facilities.
Issue 4.3 Should the definition of the transmission charge determinants, used to establish UTRs and bill transmission charges, be revised to exclude the impact of planned transmission outages on customers with multiple delivery points?	No, double peak billing is addressed via OEB staff's submission on Issue 4.1
Issue 4.4 Should the double-peak billing impact of planned and unplanned transmission outages be tracked in a deferral account?	No, double peak billing is addressed via OEB staff's submission on Issue 4.1

Issue	OEB Staff Position
Issue 5.1 Should the application of gross load billing thresholds to embedded generator units be defined by generating unit or generating facility or by some other approach? This includes refurbishments approved after October 30,1998, to a generator unit that existed on or prior to October 30,1998.	Maintain status quo: apply gross load billing by generating unit basis. The approach determined in RP-1999-0044 – generating unit basis – has not been invalidated. There has not been a demonstration of a material change in cost shifting or administrative burden. Some refurbishments may require a facility level evaluation.
Issue 5.2 Is additional clarity needed on the applicability of gross load billing thresholds to embedded generation that employs inverters (such as embedded solar generation)?	Maintain status quo: inverter basis as the “generating unit.”
Issue 5.3 How should the UTR schedule apply to energy storage facilities?	Embedded Energy Storage: same treatment as renewable embedded generation Transmission Connected Energy Storage: exempt from transmission service charges when providing a service to the electricity system and the system operator
Issue 6.1 What should the gross load billing thresholds be for renewable and non-renewable embedded generation?	No basis has been provided to change the current thresholds
Issue 6.2 Should gross load billing exemptions be available in certain limited circumstances?	Yes, on a case-by-case basis

In preparing this reply submission, OEB staff has considered the submissions of several participants, including:

- Glencore Canada Corporation (GCC)
- Hydro One Networks Inc. (HONI)
- LDC Transmission Group, a coalition of several Local Distribution Companies (LDCs)
- London Property Management Association (LPMA)
- School Energy Coalition (SEC)
- Vulnerable Energy Consumers Coalition (VECC)

OEB staff's positions on the issues are unchanged from the October 16, 2024 submission. In the following, OEB staff considers each issue in light of the submissions and its own October 16, 2024 submission. Subject to any additions set out below, OEB staff relies upon its submission of October 16, 2024, and does not intend to repeat it here.

Following this, OEB staff replies to specific elements of certain submissions (see section titled "Comments on Specific Matters"). These are organized under the following topics: considering a deferral account for double peak billing (Issue 4.4); further contemplation of the questions of cost causality and fairness (Issue 4.1), in the particular context of the network service charge; the impacts to certain distribution connected customers; and OEB staff's submission on considerations for the next steps.

Issue 4: Charges caused by planned transmission outages

OEB staff views the charges caused by transmission outages as those related to a load transfer between transmission system delivery points. This is consistent with the other submissions. OEB staff submits that transmission charges should reflect the usage of those facilities upon which the charges are based. This is also consistent with submissions that argue for a delivery point basis for applying the transmission charges.

OEB staff notes that Issue 4 stems from the fact that the participating transmission customers think they are overpaying transmission charges when performing a load transfer triggered by a transmission outage. OEB staff further notes that this leads to challenges in planning and executing maintenance for transmission facilities. This is because these customers actively seek to minimize the perceived over-charging. OEB staff submits that there is only an issue with respect to the network service charge.

OEB staff's view is that allowing transmission customers to aggregate their delivery points for the network service charge would ameliorate the double peak billing concerns, at the root cause of the issue. Further, it is OEB staff's view that this would resolve the majority, or in some cases, the vast majority of the additional transmission charges associated with transmission outages.[1] This is a divergence from the other submissions.

Only some submissions identify differences between the network and connection facilities, but do so without the particular assessment that OEB staff presents. While SEC acknowledges that the situation for the network charges is different, it does so without providing details, stating that there should be a review prior to making any change.[2] While VECC appears to recognize a difference between the network and

[1] The Network Service Charge is the greatest of the three charges, even when considering the non-coincident peak charge determinant, representing at least 50% of a transmission customer's UTR cost. Additionally, some transmission customers own their transformation facilities, meaning they do not pay the transformation connection charge. For these customers, OEB staff's proposal would reduce the additional charges by approximately 80%.
[2] SEC Submission, p. 1

connection assets, VECC submits that the delivery point basis should be maintained for all transmission charges.[3]

The transmission facilities that comprise the network pool are those facilities that convey electrical energy across and throughout the entire high voltage transmission system. As such, the demand placed upon these facilities does not depend on particular delivery points: the demand placed upon these facilities relates to the flow of energy between these and all other delivery points. OEB staff submits that this provision should form part of the UTR schedule, obviating the need for an OEB application for the transmission customer who wishes to pursue this option.

The transmission facilities that comprise the asset pools for line and transformation connection charges are distinct from those of the network pool and serve a purpose particular to the delivery point. As a result, OEB staff submits that the transmission charges relating to line and transformation connection facilities that arise from load transfers reflect the usage of and benefits derived from those particular facilities. As a result, OEB staff submits that no relief is needed for these particular charges, even in the event of a transmission outage.

Consistent with most submissions on Issue 4.2, OEB staff submits that planned and unplanned outages should be treated equally. Of the submissions that addressed this issue, only HONI made a distinction between planned and unplanned outages.[4]

For Issue 4.3, OEB staff, consistent with all submissions on this issue, does not support redefining the charge determinants..

Regarding Issue 4.4, while OEB staff has concerns regarding the deferral account proposal, OEB staff does not oppose it. However, OEB staff maintains the view that only the network service charges should be relieved. OEB staff's first concern is that this is a measure to address a symptom where in fact the root cause should be contemplated and addressed. If the issue is that transmission outage initiated load transfers should not be billed, then the billing methodology should address this. This is the basis for OEB staff's submission regarding the aggregation of delivery points for the network service charge.

Additionally, OEB staff does not see any material distinction between the deferral account proposal and the relief for the "maintenance peak" charges from the Municipal Electric Association (MEA) sought in the RP-1999-0044 proceeding.[5] The OEB rejected MEA's proposal in that proceeding.[6]

Finally, OEB staff sees some dissonance in the support provided for the deferral account option. OEB staff's view is that there are many detailed submissions regarding

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[3] VECC Submission, p. 7
[4] HONI Submission, p. 4
[5] RP-1999-0044, MEA Final Argument, March 29, 2000, p. 32, available at: https://www.rds.oeb.ca/CMWebDrawer/Record/841088/File/document
[6] RP-1999-0044, Decision with Reasons, para. 3.4.9

cost causality, carefully examining the decision from RP-1999-0044 and general rate-making principles. These examinations appropriately consider the delivery point basis and the charge determinants that underlie all three transmission charges. These submissions argue in favor of delivery point charging on the basis of cost causality.[7] Yet, these same submissions argue for an external mechanism without recognizing that it would, in OEB staff's view, undermine the principles that are used to argue the delivery point basis.

Separate from OEB staff's position on the question of establishing a deferral account, OEB staff presents considerations surrounding the implementation of such a deferral account in the Comments on Specific Matters section below.

Issue 5: Basis for Billing Renewable, Non-renewable and Energy Storage Facilities for Transmission Charges

The Unit vs. Facility Basis Question

On Issue 5.1, OEB staff submits the original intent of the gross load billing threshold appears to be that it would be applied on a unit basis, and not on a facility basis. The RP-1999-0044 decision established the 1 MW gross load billing threshold by balancing the costs of metering and billing with those of cost shifting. OEB staff submits that the unit basis of gross load billing should continue, primarily on the basis that the evidence of this proceeding has not invalidated or demonstrated the insufficiency of the original basis. OEB staff does not oppose a facility basis.

OEB staff does agree that if the basis is changed from a unit to facility basis, it would be unfair to those with existing embedded generation to change the rules after the investments have been made.[8] OEB staff is weary of yet another layer of complexity to the UTR schedules that would be applied to institute a second set of "existing embedded generation." Changing to a facility basis naturally begs the question of what a facility level threshold should be. Furthermore, OEB staff notes that HONI seeks to eliminate the recognition of existing embedded generation altogether.[9]

Similar to the other submissions that consider this question, OEB staff looked to the RP-1999-0044 decision as a point of reference. Contrary to VECC's submission, OEB staff submits that the RP-1999-0044 decision remains germane to this issue.[10] The full

[7] HONI submission, p. 2: applying transmission charges by delivery point reflects the benefits of having multiple delivery points; SEC Submission, p. 1 states that a delivery point basis for line and transformation connection charges reflects cost causality; VECC Submission, pp. 6-7, delivery point charging reflects cost causality
[8] SEC Submission, at page 2 identifies a phase-in period; VECC Submission, at page 13 identifies if there is a change, there should be consideration to grandfathering the definition for the currently existing facilities.
[9] HONI Submission, pp. 10-11
[10] VECC Submission, p. 13

paragraph referenced by VECC reads as follows, with emphasis added:[11]

> The only remaining issue, in the Board's view, is that of administrative costs and simplicity. Gross load billing for smaller loads would require the installation of metering and the incorporation of these loads in the IMO's billing and settlement process, thus creating costs and complexities for both the generator and the system as a whole which would likely outweigh any benefits from billing for such facilities. The Board also notes from the information provided that generators of less than 1 MW are also exempt from IMO dispatch and scheduling requirements. *The Board therefore accepts OHNC's proposal*.

First, OEB staff notes the context for stating that "the only remaining issue" is that administrative costs and simplicity merit consideration. It is important to consider why this is identified as the only remaining issue. This context begins with the determination that gross load billing shall apply to line and transformation connection charges:[12]

> Given the Board's findings above that net load billing shall apply for network transmission service, the issue remains as to the appropriateness of the requested exemption for connection facilities and the specific threshold for new embedded generation.

Where "the Board's findings above" are:[13]

> The Board therefore finds that for load customers with new embedded generation the charges for Line and Transformation Connection service should be based on gross load billing.

The "only remaining issue" was that of administrative costs and simplicity since "it is not clear as to the extent to which some of the specific recommendations [regarding exemptions from gross load billing] advanced by certain parties can hold in light of the Board's earlier findings."[14] The "earlier findings" are those noted above on net load and gross load billing.

VECC appears to agree with HONI's view that the 1 MW threshold was based on Independent Electricity System Operator (IESO) dispatch and scheduling requirements and that this is not a valid consideration for that threshold.[15] OEB staff disagrees with VECC and HONI that RP-1999-0044 decision determined the 1 MW gross load billing threshold on the basis of IESO dispatch and scheduling requirements. OEB staff submits that from the above, the determination of the 1 MW threshold in relation to gross load billing was based on accepting the applicant's proposal.

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[11] RP-1999-0044 Decision with Reasons, para. 3.2.44
[12] RP-1999-0044 Decision with Reasons, para. 3.2.41
[13] RP-1999-0044 Decision with Reasons, para. 3.2.39
[14] RP-1999-0044 Decision with Reasons, para. 3.2.43
[15] VECC Submission, pp. 12-13, 16

The applicant's proposal is summarized in the decision as follows:[16]

> For reasons of administrative simplicity and cost efficiency, OHNC proposed that new embedded generation under 1 MW serving existing load should be exempt from gross load billing and be billed on a net load basis. It was OHNC's view that the minimal cost shifting resulting from such small scale generation would not justify the costs of metering and billing.

With this context, OEB staff submits that there are two questions to answer. First, has the degree of cost shifting changed? Second, has the nature of the costs of metering and billing changed? VECC provides "preliminary observations" on these questions that are intertwined with VECC's submission on Issue 6.1.[17] While OEB staff agrees with the relevance of the facts that VECC has brought forward regarding administrative costs, metering costs, and cost shifting, OEB staff submits that the above questions remain unanswered. As such, OEB staff submits that the status quo has not been invalidated.

The nature of assessing transmission connections is brought forward as another matter related to this question. OEB staff does not dispute VECC's statement that "[f]or both connection impact assessment purposes and longer term planning purposes, it is the potential load at the point where the customer connects to the transmission system that determines the level of transmission service that needs to be provided and the resulting costs."[18] However, OEB staff does not see how the application of the gross load billing threshold affects, or is related to, the arithmetic of a transmission customer's net demand at the transmission connection.

OEB staff also submits that when considering gross load billing, it is also important to consider whether it is a situation where additional embedded generation offsets existing load or it is embedded generation that accompanies new load. It appears to OEB staff that the notion of applying the logic of transmission connections to gross load billing may fail to fully appreciate or reflect that the purpose of gross load billing is to address the concern of stranded asset costs.[19] OEB staff does not dispute VECC's assessment of transmission connections. However, OEB staff submits that to consider a change in the basis for applying gross load billing threshold, the most appropriate starting point is the original basis.

Finally, OEB staff notes that, qualitatively, there is an additional administrative burden with implementing yet another grandfathering definition for another set of "existing embedded generation."[20] OEB staff has a similar sentiment regarding implementing a

[16] RP-1999-0044 Decision with Reasons, para. 3.2.40
[17] VECC Submission, p. 17
[18] VECC Submission, p. 13
[19] RP-1999-0044, Decision with Reasons, para. 3.2.38 and 3.2.39
[20] VECC Submission, p. 13, where VECC suggests a new set of grandfathered facilities to reflect the change from unit basis.

phased approach to changing the basis for evaluating the gross load billing threshold.[21]

Other Sub-Issues to Issue 5

On the matter of refurbishments to units that existed prior to October 30, 1998, the other aspect of Issue 5.1, OEB staff submits that the basis for the gross load billing threshold is demand bypass with respect to the transmission connection facilities. OEB staff submits that this threshold should be assessed on a consistent basis, and that the current generating unit basis has not been invalidated. However, in some cases, such as when the transmitter and the customer accept that a refurbishment of those units can change the number of units at the facility, the principle should guide the application of the threshold. As such, OEB staff affirms the views provided in IRE-2021-0210, which is included as Appendix A to the HONI Background Report. In this particular case, it is appropriate to apply the threshold to the increased capacity of the facility.

For Issue 5.2, OEB staff submits, on the basis of supporting a “per unit” application of the gross load billing threshold, that there is no convincing reason to deviate from how HONI has been applying the threshold to the inverter capacity of inverter-based facilities. The submissions on this issue are divided, but also aligned with the respective submissions to Issue 5.1: those who argued for a facility basis to the gross load billing threshold were consistent in also taking the position that it should be applied at the facility level for embedded solar generation and vice versa.

For Issue 5.3, OEB staff submits that the gross load billing threshold for embedded energy storage facilities should be the same as renewable embedded generation facilities, as this would be consistent with the RP-2022-0120 decision that established the 2 MW threshold.

OEB staff’s submission was the only one that considered Issue 5.3 in the context of transmission connected energy storage facilities. OEB staff submits that these facilities should be exempt from transmission service charges when providing a service to the transmission system. OEB staff submits that these energy storage facilities should be considered to be providing a service when any of the following occur: the facility is responding to an IESO load dispatch in real-time, scheduled for operating reserve, providing frequency response, providing voltage regulation, or addressing a system reliability concern. OEB staff submits that transmission connected energy storage facilities should incur transmission service charges for the demand associated with station service or when withdrawing energy from the transmission system on a self-scheduling basis.

[21] SEC Submission, p. 2, where SEC suggests a phase-in approach in consideration of fairness to existing embedded generation investments.

Issue 6: Gross load billing thresholds for renewable and non-renewable generation

Regarding Issue 6.1, OEB staff submits that there is insufficient evidence as part of this proceeding to suggest the OEB should change the gross load billing thresholds for line and transformation connection charges. As previously noted, VECC's submission provides a helpful summary of the facts related to the gross load billing threshold.[22] HONI states that the impacts of changing the gross load billing threshold would require further examination.[23] OEB staff agrees that the evidence has not clearly demonstrated a change in the nature of the administrative and metering costs or the cost shifting occurring due to the application of the current gross load billing threshold.

For Issue 6.2, OEB staff submits that the UTR schedule should identify that transmitters could seek exemptions under specific circumstances, such as those when the level of gross load billing would exceed the capacity of the line and transformation connection facilities.

OEB staff submits that GCC's situation, as presented in Exhibit M3, could be another example of a logical exemption. While OEB staff disagrees that all the Retail Transmission Service Rates (RTSRs) that are charged to GCC when drawing load from Larchwood TS are "wholly duplicative" of the pre-load transfer condition, OEB staff submits that the network service RTSR is duplicative. During a load transfer, different connection facilities are used to different degrees than before the load transfer. Therefore, OEB staff submits that the line and transformation connection RTSRs are not duplicative. OEB staff takes this position regardless of whether GCC's load was considered in the design of Larchwood TS; GCC is using these facilities. OEB staff submits that GCC should, in accordance with the user pay principle, be appropriately charged for this usage.

Furthermore, GCC's situation is a one-off situation.[24] GCC's load transfers are relatively rare, with some years having no load transfers and being at a frequency of less than one instance per year in the last five years.[25] OEB staff submits that a "one off" situation such as GCC's merits a "one off" solution.

OEB staff notes that the meters utilized during the load transfer are both temporary and owned by HONI.[26] OEB staff submits that, predicated on the rare nature of GCC's load transfers and presuming that GCC can demonstrate materiality, it would be reasonable for GCC request that the IESO and Hydro One Distribution coordinate the "one-off" billing to GCC under the load transfer condition. If either or both Hydro One Distribution and the IESO deem the administrative effort incongruous with the amount charged to GCC for network service, i.e., approximately $35,000 in GCC's evidence, yet the OEB

[22] VECC Submission, p. 17
[23] HONI Submission, pp. 13-14
[24] GCC Submission, para. 9
[25] GCC Response to Interrogatory M3-Staff-10, parts c) and e)
[26] GCC Response to Interrogatory M3-Staff-9, parts a) and e)

finds that this charge is indeed duplicative, then OEB staff submits that Hydro One Distribution should be allowed to seek exemption from charging GCC the RTSR-Network charge under the load transfer conditions presented in this proceeding.

Comments on Specific Matters

OEB staff maintains that cost causality and materiality should be the core guiding principles for resolving the issues. The balance of this submission pertains to more complex aspects of other parties' submissions. This begins with OEB staff's concerns regarding the implementation of a deferral account or accounts to reduce the costs of transmission outage initiated double peak billing events. Then OEB staff will comment on the cost causality and fairness considerations relating to network service charges. OEB staff also endeavors to provide helpful input regarding the question of certain distribution connected customers. Finally, OEB staff offers submissions on the next steps, including the proposed formation of a working group brought forward in some submissions.

Issue 4.4: Deferral Account for Double Peak Billing

Many submissions consider HONI's "Option 4," which is a deferral account to track the impacts of double peak billing. This has been generally supported.[27] The general proposal is that the transmitter would issue refunds to transmission customers, outside the IESO settlement process, and then record the refunded amount in a deferral account. In this way the transmission customers would be refunded the double peak billing charges and then the transmitter would seek disposition of the variance account to recoup the lost revenue.

This proposal is the most popular, with many participants submitting benefits to this proposal. VECC identified it to be its most preferred of HONI's options, acknowledging the benefits identified in the HONI Background Report. These were: no changes to IESO settlement processes, IESO's administration of transmission charges, or the UTR schedule; no changes to HONI's forecasting; and no risk to the transmitters' cost recovery.[28] In its submission, HONI also noted that a deferral account could be implemented more quickly than the other options.[29] All submissions that supported this proposal highlighted benefits of transparency. LPMA see this as an interim solution.[30]

That said, several supporting submissions either include caveats to the support or highlight that the proposal is incomplete. HONI identified concerns that transmitters would take on some responsibilities for settlement and take on additional administrative costs, costs that HONI submits should be included in the deferral account.[31] HONI also

[27] In their submissions, GCC, HONI, LPMA, SEC, and VECC all seem to support the deferral account option. The LDC Transmission Group seems to not oppose it, although it favours a different solution.
[28] HONI Background Report, section 1.4.4.1
[29] HONI Submission, p. 8
[30] LPMA Submission, p. 6
[31] HONI Submission, pp. 8-9

identified that further steps would be required to establish the methodology to determine the refund amount.[32] SEC noted "there are details that will need to be worked out".[33] VECC highlighted several unanswered questions, submitting that a working group would be useful in addressing and resolving issues relating to the implementation of a deferral account.[34] When presenting this option, HONI identified disposition at the time of rebasing, whereas LPMA submitted that disposition should be included as part of annual applications.[35] [36]

While OEB staff suggests that its submission on Issue 4.1 resolves the double peak billing issue without the need for a deferral account, OEB staff does not oppose the deferral account option. OEB staff agrees with the above that the details of such an account will need to be resolved should the OEB approve such an account. In addition to the additional considerations brought forward in the other submissions, OEB staff offers the following comments on the implementation of such a deferral account.

HONI stated reservations regarding transmitters taking on accountabilities in the settlement of transmission charges that are currently the responsibility of the IESO. OEB staff concurs. The proposed refunds, since they are issued by the transmitters, would introduce transactions that are executed outside the IESO's standard process. The lack of a central settlement record may make it difficult to audit or verify the associated transactions. OEB staff submits that this could cause confusion where both the IESO and the OEB now have regulatory oversight over the settlement of transmission charges. OEB staff questions whether a transmitter should be settling a portion of transmission charges without the oversight of the IESO.

OEB staff's other concern relates to the review of this potential deferral account and what it means for established Group 1 Retail Settlement Variance Accounts, namely Account 1584 – RSVA Retail Transmission Network Connection Charges Account and Account 1586 – RSVA Retail Transmission Connection Charge Account (going forward, referred to as "RSVAs" even though there are other Retail Settlement Variance Accounts). Many submissions espouse the benefits of transparency that would come with the OEB's prudence review of additions to the proposed account.[37] OEB staff finds the procedural implications of the prudence review problematic for a number of reasons.

First, it is difficult to distinguish the underlying event. The LDC Transmission Group has noted that, historically, it does not track the particular impacts of transmission outage

[32] HONI Submission, p. 8, lines 16-19
[33] SEC Submission, p. 2
[34] VECC Submission, pp. 9-10
[35] HONI Background Report, Issue 4, p. 11, lines 21 and 22
[36] LPMA Submission, p. 5
[37] HONI Submission, p. 7, stating that the regulatory process would bring clear visibility to the magnitude and impact of double peak billing events; LPMA Submission, p. 5; identifying what information should be provided to document account additions; SEC Submission, p. 2, stating that a deferral account is the most transparent option; VECC Submission, p. 8, stating that a deferral account (Option 4) is more transparent than the option of revising charge determinants due to the OEB's review prior to disposition

initiated load transfers nor distinguish them from other activities that may accompany the load transfer.[38] Furthermore, HONI has identified that it does not have a proposed methodology to quantify the refund associated with transmission outage initiated load transfers.[39]

Additionally, OEB staff submits that the prudence review itself must be considered. The first complication is the timing of disposition. For the transmitter, HONI has proposed that the balance be disposed as part of a re-base application. As this deferral account would be a Group 2 variance account that requires a panel of commissioners to review and approve disposition, this is logical. However, LPMA submitted that the disposition should be annual, meaning that any annual update for setting a transmitter's rates with balances in this deferral account would require a panel of commissioners, eliminating the regulatory efficiency of mechanistic annual updates.

For the LDCs, the proposed refunds would have an impact on the Network and Connection RSVAs. These two Group 1 accounts would have to capture the net impact to the LDCs that includes the refund and then pass the amount to the LDCs' customers. If participants seek prudence review at the time that the LDC comes before the OEB, this would subject the Group 1 variance accounts to a prudence review, eliminating the regulatory efficiency afforded to Group 1 DVAs. If the refunds to LDCs are not subject to prudence review, then the refund will be accepted with the mechanistic approval of the disposition of the Group 1 accounts. In this case, the transmitter is at risk upon their disposition: if prudence is not demonstrated at that time, or there are errors in the determination and quantification of the impact of the transmission outage, there may be disallowances.

OEB staff is also concerned about the level of effort that would be required for a transmitter to demonstrate prudence. OEB staff notes that HONI appears to substantiate the degree of incremental effort, stating HONI would seek to include all the costs associated with administering the process related to such a deferral account as part of the account.[40] These unquantified costs, which would be caused by managing and documenting refunds to specific LDCs, would then be collected from all transmission customers. In the context of other claims regarding "anomalous outcomes," OEB staff questions whether this cost-sharing for the benefit of select customers is appropriate.[41]

The preceding comments assume there is only a deferral account held by the transmitter. However, HONI has suggested that host distributors should also be considered in situations where their embedded LDC customers or sub-transmission customers are affected by transmission outage initiated load transfers.[42] In this situation

[38] LDC Transmission Group Responses to Interrogatories M1-Staff-1, part c) and M1-Staff-5, part d)
[39] HONI Background Report, Issue 4, section 1.4.4.3
[40] HONI Submission, p. 8 line 39 through to p.9 line 2
[41] HONI Background Report, Issue 4, section 1.4.2.2, relating to "anomalous outcomes" regarding the dilution of benefits due to the nature of RTSR related rate riders
[42] HONI Response to Clarification Question GCC-1, Response 6, part a)

the host distributor's variance account, as a Group 2 account, would require a panel of commissioners to review and approve any disposition. OEB staff has already submitted concerns regarding the potential for inter-related variance accounts between LDCs and transmitters.[43]

Both HONI and the LDC Transmission Group have identified the steps taken to minimize double peak billing charges.[44] It appears to OEB staff that the difficulties that arise in planning and executing maintenance of the transmission system is motivating parties to seek a resolution. OEB staff submits that a deferral account is not the optimal tool to address transmission customer behaviors that seem to be uniformly characterized as undesirable.

Issue 4.1: Questions Relating to Cost Causality and Fairness

In this section, OEB staff responds to particular aspects of VECC's and HONI's submissions. VECC states that aggregating delivery points for the network service charge would contravene the principles of cost causality. HONI questions the fairness of aggregating delivery points. OEB staff does not fully agree with these submissions.

OEB staff agrees with VECC that the principles of cost causality and Bonbright's attributes of a sound rate structure are important guiding principles in consideration of the issues to this proceeding.[45] However, OEB staff notes a divergence in the application of these principles to the question of delivery point aggregation in the context of the network service charge.

OEB staff questions VECC's assertion that the delivery point basis is inextricably linked to the charge determinants.[46] OEB staff notes that the OEB's determination of the delivery point basis in RP-1999-0044 was separate from the determinations regarding the network service pool's charge determinants.[47] The OEB's finding on the delivery point basis does not consider the distinction between the transmission network facilities and the transmission connection facilities, despite making the distinction when considering the asset pools and the charge determinants.[48] VECC equally recognizes this distinction between the sets of facilities.[49]

HONI's concerns regarding fairness also seem to consider all three transmission charges together, without addressing the differences between the asset pools,

[43] OEB Staff Submission, p. 10
[44] HONI Submission, p.4 and LDC Transmission Group Submission, pp. 1-2
[45] VECC Submission, p. 3
[46] VECC Submission, p. 6
[47] The RP-1999-0044 finding that determined a delivery point basis for all transmission charges was stated in paragraph 3.4.9 in the sub-section titled "Charges Per Delivery Point." The findings related to the network service charge determinant were stated in paragraphs 3.4.21 to 3.4.30, without specific reference to paragraph 3.4.9.
[48] RP-1999-0044, Decision with Reasons, para. 3.4.33
[49] VECC Submission, p. 6

identifying concerns if delivery points are aggregated.[50] This is on the basis that the aggregated peak demand may be less than the sum of the individual delivery points.[51] VECC confirms this is probable.[52] While OEB staff agrees, OEB staff submits that the nature and usage of the given transmission facilities should also be considered. OEB staff submits that, with respect to the network transmission facilities, the customer's aggregated demand is a reflection of the demand placed on those facilities

To illustrate this point, OEB staff presents the following hypothetical monthly coincident and non-coincident peaks for a transmission customer with three delivery points:

Table 2: Hypothetical Coincident and Non-Coincident Monthly Peak

DP-A	DP-B	DP-C	System Peak?	∑customer
30	20	20	no	70
20	30	30	yes	80

In agreement with VECC and HONI, OEB staff submits that the individual non-coincident peaks of each individual delivery point reflect the usage of the transmission connection facilities. However, with respect to the customer's usage of, and demand placed upon, the network transmission facilities, OEB staff contends that the sum of the delivery points reflect this demand. While it is clear that the sum of the individual peaks of each delivery point, 90 (derived by the sum of each delivery point: 30+30+30), is greater than the aggregated sum, 80 during the hour of system peak, OEB staff does not see how the former reflects the demand placed upon the network transmission facilities. Since the purpose of the network facilities is to convey electrical energy between the generators in the transmission system and the various loads, the customer has not put the demand of 90 on the network.

OEB staff sees the systemic nature of the network transmission facilities as analogous to the "global" nature of certain supply costs. OEB staff notes that the Global Adjustment, a monthly supply charge, is applied at the customer resolution.[53]

In addition to the noted findings on the definition of the network service pool, the OEB also made the finding that that the network pool charge determinants shall use a pool-based, uniform methodology, where locational transmission pricing was not considered as an option.[54] Despite this, VECC raises concerns regarding distributors that operate in more than one region of the province and operate with non-contiguous service areas.[55] HONI also submits that, even though it does not support aggregation of delivery points, HONI prefers selective aggregation over customer aggregation as this would only allow

[50] HONI Submission, p. 2
[51] HONI Background Report, Issue 4, section 1.4.2.2
[52] VECC Submission, p. 7
[53] IESO Market Rules – Settlements – IESO Charge Types and Equations: the allocated quantity of energy withdrawn for Global Adjustment is that of the market participant, as defined for the GA_AQEW variable
[54] RP-1999-0044, Decision with Reasons, para. 3.4.21
[55] VECC Submission, p. 6

"for aggregation of delivery points for those situations where electricity can in fact be shared across them."[56]

If the OEB finds these to be credible concerns, OEB staff suggests that the OEB consider the IESO's 10 electrical zones.[57] The IESO plans and operates the high voltage transmission system by considering interfaces that form internal boundaries between the IESO's 10 defined electrical zones.[58] Therefore, if the OEB accepts that geographical considerations are valid in the context of the network service charge and its uniform transmission rate, OEB staff submits that these electrical zones could form a logical basis for organizing and aggregating delivery points.

Impact to Distribution Connected Customers

In Procedural Order No. 3, the OEB stated, among other things, that:[59]

> This phase of the OEB's generic proceeding deals only with UTRs, so the impacts of double-peak billing on distribution-connected customers will not be examined.

Submissions from HONI, SEC, and VECC included specific elements relating to distribution connected customers.

The concerns of distribution connected customers were introduced to this proceeding through the HONI Background Report:[60]

> It is Hydro One's view that, for the following two reasons, the distribution issues will also need to be addressed either in parallel to or after the transmission issues are addressed as part of the current proceeding: First, from a consistency perspective a decision in respect of transmission-connected customers can be applied on the distribution side, provided that customers who may be impacted by the decision are involved in the proceeding. Second, as explained in detail in Sections 1.4.2.2, 1.4.3.2, and 1.4.4.2 below, there is an anomalous/unfair outcome for customers if double-peak billing issues are resolved for transmission connected customers but not for distribution-connected customers.

On July 10, 2024, Entegrus (EPI) filed a letter of comment to the OEB, which concludes with:

> Transmission-connected double-peak billing and distribution-connected double-peak billing are often fundamentally intertwined. This issue can have a considerable financial impact on customers

56 HONI Submission, p. 3
57 [IESO Zonal Map]
58 IESO *Annual Planning Outlook*, March 2024, section 3.3.1
59 Procedural Order No. 3, p. 3
60 HONI Background Report, Issue 4, p. 5

> that should not be lost. EPI appreciates your consideration of this matter.

OEB staff submits the concerns raised in the Entegrus letter are related to the anomalous outcomes raised by HONI. These anomalies are described in section 1.4.2.2 of the HONI Background Report: when the transmission customer has been afforded relief in respect of transmission charges under a transmission outage initiated load transfer, it will pass these savings on to its customers via the RSVA rate riders that relate to the RTSR revenues and transmission charges of that transmission customer. If the load transfer pertained to or directly affected the sub-transmission customer, the relief is diluted through the allocation of the RSVA rate rider among all of the host distributor's customers.

HONI was asked about these anomalous outcomes in the Clarifying Questions to HONI's Background Report. HONI stated that if a change in UTRs is translated to the RTSRs, the concern is likely to be relieved. Specifically, HONI stated this would be the case if delivery points are aggregated for embedded LDCs or sub-transmission customers.[61] Equally, HONI stated this would also be the case if the deferral account solution is provided to host distributors.[62] OEB staff is inclined to agree, noting that this is predicated on the alignment between the UTRs and RTSRs, and also the assumption that timing differences in rate adjustments would be minimal. Without proper alignment or with significant time differences, the relief may not materialize.

OEB staff submits that consideration could also be given to an interim variance account for a potential temporary solution where the host distributor can *extend* the relief it receives, in whichever form the OEB decides to provide such relief, to its own embedded customer or customers. This statement is made separate from Issue 4.4. For example, if the OEB determines that some form of delivery point aggregation should be implemented while similar aggregation is not immediately applied to RTSRs, a deferral account for the host distributor could be established to ensure that the embedded distributor is not left behind.

OEB Staff Submission Regarding Next Steps

In this section, OEB staff offers comments on steps that would follow any findings, and addresses the suggestion for a double peak billing working group.

On the first matter, OEB staff assumes that any findings will require additional procedural steps, such as incorporation into the UTR schedule or an accounting order. OEB staff suggests that revisions to the UTR schedule may benefit from input from the participants in this proceeding, particularly HONI and the IESO. As a result, OEB staff recommends that the OEB consider further procedural steps akin to a draft rate order

[61] HONI Response to Clarifying Question GCC-1, response 4, part i)
[62] HONI Response to Clarifying Question GCC-1, response 6, part a)

phase. This would allow the OEB to consider how to implement findings into the UTR schedule. Additionally, if the OEB accepts the deferral account proposal, OEB staff submits that the drafting of the accounting order should be part of this phase to the generic hearing.

OEB staff submits that the suggested working group is not necessary. The broadest working group suggestion was that of LPMA, mentioning a working group in each part of Issue 4, concluding with the following:[63]

> LPMA submits that the OEB should set up a working group consisting of members from the IESO, HONI, the LDC Group, the OEB, industrial customers and any other interested parties to review the potential solutions put forward in the HONI Report and in the LDC Group evidence, as well as any other potential solution that may come forward. This review would get into the details of each potential solution and look at the issues of fairness, practicality and incremental costs needed to implement each solution and bring this information back to the OEB and interested parties to review.

OEB staff notes that this phase of the generic hearing commenced with an invitation to a stakeholder conference that was extended to all intervenors in Phase 1, EB-2021-0243, all Licensed and Rate-Regulated Electricity Transmitters and Distributors, and all Licensed Electricity Generators and Electricity Storage Companies.[64] Any of those recipients could participate in this generic hearing and the OEB made provision for any participant to propose evidence as part of this hearing.[65] The OEB cast a wide net for participants in this proceeding.

VECC supports the LDC Transmission Group's suggested working group, focusing on the implementation of deferral accounts.[66]

OEB staff submits that there is sufficient evidence in this proceeding for the OEB to make a determination regarding the double peak billing issue or an associated deferral account. Furthermore, OEB staff submits that an appropriate accounting order could be developed as part of this proceeding to establish the deferral account.

~All of which is respectfully submitted~

[63] LPMA Submission, p. 6
[64] OEB Letter, Invitation to stakeholder conference to discuss options and next steps for Phase 2, December 20, 2022
[65] Procedural Order No. 2
[66] VECC Submission, pp. 9-10