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

DECISION AND ORDER

EB-2022-0325

GENERIC HEARING ON UNIFORM TRANSMISSION RATES – PHASE 2

Decision on Issues 4, 5, and 6

BEFORE: Pankaj Sardana
Presiding Commissioner

Fred Cass
Commissioner

Michael Janigan
Commissioner

March 27, 2025

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

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1 OVERVIEW

This is a decision on Issues 4, 5, and 6 as part of the second phase of the OEB's generic hearing to consider various issues related to Uniform Transmission Rates (UTRs). These three issues relate to the following topics: the charges caused by transmission outages; the basis for billing renewable, non-renewable, and energy storage facilities for transmission charges; and gross load billing thresholds for renewable and non-renewable generation.

The OEB issued a decision on Issues 1, 2, and 3 of this proceeding on May 9, 2024. Those issues related to the timing of UTR decisions, the number of decimal places for UTRs, and prorating transmission charges for new connections to account for when the connection took place in the month.

All six of these issues were identified in the first phase of the generic hearing on UTRs,[1] which considered the setting of the Export Transmission Service rate. The notice in that proceeding also identified the calculation of the Network Service Charge determinant as a UTR-related issue. This latter issue has not been examined as part of this phase of the generic hearing.

Issue 4 to this proceeding considered the charges caused by planned transmission outages. These charges are termed "double-peak billing." This is because customers with multiple delivery points who perform load transfers to maintain supply during outages within a month experience two monthly peaks for transmission service. This is because the transmission charge determinants are set on a monthly basis. The submissions to the OEB show disparate views on this matter.

As detailed below, the OEB will convene a Working Group, facilitated by OEB staff, to report back to the OEB on whether double-peak billing is a material issue that requires a mechanism to be established to address it, and proposals for what the mechanism should be.

Issue 5 considered the basis for billing renewable, non-renewable, and energy storage facilities. The OEB finds that, at this time, it is appropriate to maintain the status quo in applying the gross load billing threshold, that energy storage facilities shall have gross load billing applied at the same threshold as renewable embedded generation facilities,

[1] EB-2021-0243

and that transmission-connected energy storage facilities shall be exempt from transmission charges under certain conditions.

The conditions under which transmission-connected energy storage facilities are exempt from transmission charges are those when the facility is providing any of operating reserve, frequency regulation, voltage regulation, responding to real-time market dispatch signals from the IESO, or supporting the IESO for transmission system reliability.

Issue 6 considered gross load billing thresholds for renewable and non-renewable generation. The OEB finds it appropriate to maintain the current gross load billing thresholds at this time. The OEB also finds it appropriate for there to be exemptions to gross load billing under certain circumstances, such as when a customer installs embedded generation to serve their own new load and the transmission system is constrained and cannot supply that full load.

Several questions were raised through the course of the proceeding that the OEB identified as out of scope in this phase of the generic hearing. As a result, there are several matters that may be considered by the OEB at a later date. These include an examination into the Network Service Charge methodology, a comprehensive examination into gross load billing, an examination of gross load billing thresholds, and if there are any considerations for distribution-connected customers with respect to the outcomes of the Working Group.

2 CONTEXT AND PROCESS

The Ontario Energy Board (OEB) established a generic public hearing on its own motion under sections 19, 21 and 78 of the *Ontario Energy Board Act, 1998* (the OEB Act) to consider various issues related to Ontario's Uniform Transmission Rates (UTRs). This is the second phase of this proceeding.

A Notice of Hearing was issued on October 27, 2023. In the Notice of Hearing (Notice), the OEB identified the following six issues:

1) The timing of UTR decisions
2) Number of decimal places for UTRs
3) Prorating transmission charges for new connections to account for when the connection took place in the month
4) Charges caused by planned transmission outages
5) Basis for billing renewable, non-renewable, and energy storage facilities for transmission
6) Gross load billing thresholds for renewable and non-renewable generation

On December 3, 2024, the OEB issued Procedural Order No 1. Except for those who had written to the OEB to indicate otherwise, all parties from Phase 1 of the generic hearing on UTR-related issues[2], were deemed intervenors in this proceeding with the same cost eligibility status. Procedural Order No. 1 established 28 intervenors. The following intervenors actively participated in this proceeding:

- Association of Major Power Consumers of Ontario (AMPCO)
- Association of Power Producers of Ontario (APPrO)
- Canadian Niagara Power Inc.
- Distributed Resource Coalition (DRC)
- Energy Storage Canada (ESC)
- Entegrus Powerlines Inc.
- Environmental Defence Canada Inc. (ED)
- ENWIN Utilities Inc.
- Glencore Canada Corporation (GCC)
- Halton Hills Hydro Inc.
- Hydro One Networks Inc. (HONI)

[2] EB-2021-0243, Generic hearing on Uniform Transmission Rate-related issues and the Export Transmission Service Rate

- Independent Electricity System Operator (IESO)
- London Property Management Association (LPMA)
- Niagara-on-the-Lake Hydro Inc.
- School Energy Coalition (SEC)
- Vulnerable Energy Consumers Coalition (VECC)

DRC, ESC, and ED applied for and were granted cost eligibility in this proceeding. Cost eligibility status of AMPCO, APPrO, LPMA, SEC, and VECC was maintained from Phase 1 of the proceeding.

Procedural Order No. 1 also directed HONI to file a background report on Issues 4, 5, and 6 (HONI Background Report). The HONI Background Report supported the proceeding by providing HONI's view of the issues.

The OEB approved the detailed issues list in Procedural Order No. 3 on July 5, 2024. In that procedural order, one of the OEB's findings was that this phase of the generic proceeding would only deal with UTRs. As a result, the impacts of double-peak billing on distribution-connected customers were not examined.

Procedural Order No. 4, issued July 29, 2024, gave leave for certain intervenors to file evidence. On August 29, 2024, a group of local distribution companies (LDCs), Niagara-on-the-Lake Hydro Inc., Canadian Niagara Power Inc., ENWIN Utilities Inc., Entegrus Powerlines Inc., and Halton Hills Hydro Inc. (the LDC Transmission Group), jointly filed a submission in collaboration with Milton Hydro Inc., Kingston Hydro Inc., Wellington North Power Inc., Hearst Power Distribution Company Inc., and Renfrew Hydro Inc. GCC also filed a submission. Both submissions were specific to Issue 4.

Procedural Order No. 4 allowed for OEB staff and the parties to file submissions on Issues 4, 5, and 6, by October 16, 2024 and the opportunity to file reply submissions by October 30, 2024. Many of the submissions considered the historical basis for the transmission charges, examining the context and decision of the original UTR proceeding.[3]

[3] The UTRs were first established through RP-1999-0044, an Application by Ontario Hydro Networks Company Inc., for an Order or Orders approving year 2000 transmission cost allocation and rate design. Ontario Hydro Networks Company Inc. was the predecessor to Hydro One Networks Inc.

3 DECISION ON ISSUES 4, 5, AND 6

3.1 Issue 4: Charges caused by planned transmission outages

Description of the Issue

In the Notice, Issue 4 is described as follows:

> In a month when a planned transmission outage occurs, a transmission customer that transfers its load to another of its delivery points is charged more than it would be if the outage did not occur. This is because transmission charges are based on the monthly peak at each delivery point.

The increased charge due to the load transfer in response to a transmission outage is referred to as “double-peak billing.” The sub-issues to Issue 4 reflect options presented in the HONI Background Report to address the perceived issue of double-peak billing due to planned transmission outages. The sub-issues are:

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?

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?

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?

4.4 Should the double-peak billing impact of planned and unplanned transmission outages be tracked in a deferral account?

The HONI Background Report and the evidence submitted by the LDC Transmission Group and GCC described the issues associated with double-peak billing.

These submissions described how a double-peak billing event can occur where a transmission customer with multiple delivery points performs an intra-month load transfer to maintain supply in response to a transmission outage. When a transmission customer with more than one delivery point transfers load from one delivery point to another due to an outage, the delivery point with no load still records its earlier peak. This will occur while the other delivery point serves the combined load, resulting in a higher peak. This results in the customer being charged for peaks at both delivery points, without the customer consuming more energy and even though one delivery point was unused for a period of time.

Intervenor Evidence on Double-Peak Billing

Procedural Order No 3, issued July 5, 2024, gave leave to the LDC Transmission Group, ENWIN Utilities Inc., and GCC to file evidence relating to Issue 4. Subsequently, ENWIN Utilities Inc. coordinated with the LDC Transmission Group to submit their proposed evidence under the LDC Transmission Group's evidence.

The LDC Transmission Group provided examples of double-peak billing related to transmissions outages, also describing the configuration of transmission connections for many of those LDCs. The examples provided a mix of planned and unplanned outages, in many cases quantifying the monetary impact to the LDCs' customers. The evidence also confirmed that these costs are pass through costs, meaning that the given LDC does not bear the incremental cost. Instead, these costs are passed on to the LDC customers in a future period via standard variance accounts. The LDC Transmission Group explained that its concerns relate to the impact on their customers, and that their interest lies in protecting their customers from these additional charges.

The LDC Transmission Group evidence also explained many of the actions that the LDCs take to reduce the double-peak billing costs for planned outages. These actions relate to coordinating the execution of HONI's planned outages so that the start and end of the transmission outage aligns with the month or that the outage occurs during low demand periods.

Sometimes these outages will be planned to coordinate with other work, including that of the LDCs, to maximize the amount of work that can be done while the connection is out of service. In other instances, LDCs may coordinate with HONI so that the connection remains unserved for a portion of the billing period.

The LDC Transmission Group explained that these actions are taken to avoid double-peak billing, and that these actions also have their own associated costs. The LDC Transmission Group's evidence described overtime costs as well as potential safety risks associated with switching at midnight so that the load transfer coincides with the start or end of the month. The evidence also described the additional planning and engineering costs associated with optimizing the redistributed load as well as reliability risks in the event of an unplanned outage when fewer delivery points are being utilized.

The LDC Transmission Group also described the consequences of these actions. Some of those consequences were extended outage duration, potential voltage quality issues due to the configuration with the load transfer, and additional costs associated with timing the load transfer at midnight for the start or end of the month.

GCC's evidence described its experience, as an industrial transmission-connected customer, with double-peak billing. The evidence described the configuration of the connections to supply GCC's Sudbury nickel mining and processing operations. GCC described the limitations of the transmission system to supply its load, including the lack of redundant transmission connection. As a result, during planned outages GCC is supplied by HONI Distribution.

General Comments from Parties and OEB Staff on Double-Peak Billing

AMPCO, GCC, the LDC Transmission Group, LPMA, SEC, and VECC all submitted that double-peak billing is unfair and that the OEB should provide a remedy. OEB staff submitted that double-peak billing arises from load transfers between delivery points, and this would occur for any load transfer. OEB staff submitted that for Line and Transformation Connection Charges, double-peak billing reflects the increased usage of those assets, concluding that transmission outages do not warrant special treatment. OEB staff also questioned whether billing impacts can consistently be isolated to identify the double-peak billing solely related to a transmission outage due to transmission system needs.

HONI expressed a similar view to OEB staff, that transmission charges associated with load transfers due to any type of outage are appropriate and reflect the benefit customers receive from how they use the transmission facilities. HONI stated that its concerns relate to the unintended negative consequences of customer actions to avoid double-peak billing. HONI identified that the customer actions pose challenges to planning and executing transmission system maintenance. This was the basis for HONI's position that unplanned outages do not warrant a remedy, as those consequences are not experienced during unplanned outages.

The following table summarizes the positions of the parties and OEB staff on each of the sub-issues after their reply submissions:

Issue	Position	Parties
4.1	Continue Delivery Point basis	AMPCO, HONI, SEC, VECC
	Customer Basis Aggregation, but favour a Deferral Account	LDC Transmission Group, GCC
	Aggregate for Network Service Charge, Delivery Point for Line and Transformation Connection Charges	LPMA, OEB staff
4.2	Consider both planned and unplanned outages equally	GCC, LDC Transmission Group, LPMA, SEC, VECC
	Only planned outages warrant a remedy	HONI
4.3	Oppose revising the charge determinants	AMPCO, HONI, LDC Transmission Group, SEC, VECC, OEB staff
	Do not oppose revising the charge determinants while favoring a deferral account	GCC
4.4	Establish a Deferral Account	AMPCO, GCC, HONI, LPMA, SEC, VECC
	Do not oppose a Deferral Account	LDC Transmission Group, OEB staff

HONI, the LDC Transmission Group, and OEB staff also gave some consideration to distribution-connected customers. More particularly, the LDC Transmission Group's evidence identified LDCs with a mix of transmission and distribution connections. By letter to the OEB filed July 10, 2024, Entegrus Powerlines Inc. expressed concerns, as an embedded distributor, that if a solution were implemented only for transmission-connected customers, customers like Entegrus Powerlines Inc. would not benefit from the remedy. The LDC Transmission Group proposed the OEB establish a working group to resolve the double-peak billing issue for customers with a mix of transmission and distribution system connections.[4]

OEB staff submitted that any solution implemented by the OEB should ensure that there is no imbalance between provincial transmission service charges paid by a host distributor and distribution delivery charges incurred by an embedded distributor.[5] OEB staff also submitted that GCC's situation is unique and may warrant its own solution.[6]

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?

Almost all submissions supported a delivery point basis for all three transmission charges.

HONI, VECC, and OEB staff examined the original UTR proceeding in considering their positions. They all submitted that transmission-connected customers benefit from having multiple connections to the transmission system providing increased reliability and flexibility in performing load transfers.[7] All three, along with SEC, noted that connections to the transmission system are designed and constructed for a specific transmission-connected customer or particular group of customers.[8] As a result, these submissions argued that a delivery point basis, and the resultant charges, reflect cost causality.

[4] LDC Transmission Group Reply Submission, p. 4
[5] OEB staff Submission, p. 21
[6] OEB staff Reply Submission, p. 9
[7] HONI Submission, p. 2, VECC Submission, p. 7, OEB Staff Submission, p. 5
[8] SEC Submission, p. 1

Additionally, in VECC's first submission, VECC stated that double-peak billing is primarily a Line and Transformation Connection Charge issue.[9] VECC also stated that for the Network Service Charge, double-peak billing is not a concern when a customer's peak is coincident with the system peak. HONI agreed with VECC.[10]

OEB staff submitted that only the Line and Transformation Connection Charges should be charged on a delivery point basis and that the delivery points should be aggregated for the Network Service Charge. OEB staff submitted that a delivery point basis does not reflect usage of the network transmission assets.[11] OEB staff submitted that since the purpose of these assets is to convey electrical energy through the system these assets are agnostic to the level of usage at particular delivery points. While SEC also noted that the Network Service Charge is different from the Line and Transformation Connection Charges, SEC did not support a change, since there has been no analysis of the impact of such a change and that a review of the charge determinants would likely be necessary to support such a change.[12]

In reply, VECC stated that OEB staff's view of the network assets is an oversimplification and that the original UTR proceeding also considered issues of fairness and concerns about free riders.[13] HONI also stated that the nature of the Network Service Charge determinant makes aggregating delivery points for this charge unnecessary.[14]

In reply, LPMA submitted that it was convinced by OEB staff's submissions and supported the staff view.[15] AMPCO submitted that it supports HONI and VECC in opposing delivery point aggregation.[16]

The LDC Transmission Group proposed aggregating all of a customer's delivery points for all transmission charges as a feasible solution to resolve the double-peak billing issue.[17] The LDC Transmission Group submitted that transmission-connected customers should be able to apply to the OEB to aggregate load across all their delivery points. Similarly, GCC submitted that aggregating delivery points would be an

[9] VECC Submission, p. 7
[10] HONI Reply Submission, p. 3
[11] OEB staff Submission, p. 6
[12] SEC Submission, p. 1
[13] VECC Reply Submission, p. 3
[14] HONI Reply Submission, p. 2
[15] LPMA Reply Submission, p. 2
[16] AMPCO Submission, p. 4
[17] LDC Transmission Group Submission, p. 2

"acceptable" solution.[18] However, both the LDC Transmission Group and GCC submitted that they favoured establishing a deferral account to resolve double-peak billing, as detailed under Issue 4.4.

Findings

The OEB finds that the transmission charges for line and transformation connection facilities arising from load transfers reflect the usage of and benefits derived from these facilities. Nevertheless, the OEB will consider this matter further and make a final determination on Issue 4.1 following the report back from the Working Group to be established pursuant to the OEB's findings on Issue 4.2, below. Any changes to the way UTRs are set would follow the OEB's consideration of the Working Group's recommendations. Accordingly, the OEB finds that Line and Transformation Connection Charges will continue to be set on a delivery point basis at this time.

With respect to the Network Service Charge, as has been noted by HONI, this charge is based on the higher of two conditions: 1) The delivery point's coincident peak demand in the hour of the month when the total hourly demand of all customers is highest for the month; or 2) 85% of the delivery point's peak demand during any hour between 7AM to 7PM on business days. The possibility of double-peak billing will likely only occur under the second condition. Further, the Network Service Charge billing mechanism was implemented as part of the OEB's Original UTR Decision, and the OEB finds that, while a comprehensive examination of the Network Service Charge methodology may be warranted, changing how this charge could be levied would be premature absent a complete examination into all aspects of the Network Service Charge. An examination into the Network Service Charge methodology may be undertaken in the future but is not part of this phase of the proceeding.

In summary, the OEB finds that all three Transmission Charges will continue to be charged on a delivery point basis at this time, and the matter of addressing double-peak billing because of outages is addressed below, with the findings on Issue 4.2.

[18] GCC Submission, par. 10

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?

Except for OEB staff and HONI, all submissions supported eliminating the double-peak billing charges to transmission-connected customers for both planned and unplanned transmission outages. OEB staff submitted that double-peak billing for Line and Transformation Connection Charges reflected the additional usage of these assets and did not warrant any special treatment.[19] HONI submitted that only planned transmission outages should be addressed as these are the only situations that have associated unintended consequences from customer actions that aim to minimize or prevent double-peak billing charges.[20]

AMPCO, GCC, the LDC Transmission Group, LPMA, SEC, and VECC submitted that double-peak billing due to transmission outages is unfair to transmission-connected customers. These submissions either directly stated that unplanned outages present the same degree of unfairness as planned outages, or did not make a distinction when arguing about the unfairness of the situation. In LPMA's reply submission, LPMA submitted that the reason unplanned outages should also be taken into account is customers pay for reliability and should not be paying more for a reduction in reliability.[21]

GCC and the LDC Transmission Group characterized the unfairness in terms of paying more for "the same service".[22] The LDC Transmission group submitted that it is unfair for one set of customers to, at times, pay a higher charge for the supply of energy than other transmission-connected customers.[23] The LDC Transmission Group also challenged the consistency of arguing that these customers benefit from increased reliability of service when other measures, such as Dual-Element Spot Network Transformer Stations, confer the benefits of increased reliability without attracting additional charges.[24]

In GCC's reply submission, GCC argued for a measure to address charges from HONI as a transmission-connected customer and from HONI Distribution for the same level of

[19] OEB staff Submission, p. 11
[20] HONI Submission, p. 4
[21] LPMA Reply Submission, p. 2
[22] GCC Submission, par. 7
[23] LDC Transmission Group Reply Submission, p. 1
[24] LDC Transmission Group Reply Submission, p. 2

service. OEB staff submitted that in GCC's situation, the Network Service Charge is wholly duplicative.[25] As a result, OEB staff submitted that GCC should be provided a remedy and did not make a distinction between planned or unplanned outages.[26]

In VECC's reply submission, VECC considered a transmission-connected customer's capital contribution to transmitter-owned transmission connection assets. VECC cited the *Transmission System Code* to submit that by the economic evaluation that determines the capital contribution, and then by virtue of the capital contribution itself, the customer has paid for the use of its connection facilities. VECC submitted that double-peak billing is not considered in the determination of the capital contribution. As a result, VECC submitted that the double-peak billing charges result in overcharging the transmission-connected customer.[27]

Findings

The OEB finds that before considering whether measures are needed to address a double-peak bill resulting from a planned or an unplanned outage, the OEB must first determine whether a double-peak billing problem exists. From the submissions there is no consensus on whether double-peak billing is a problem for transmitters and transmission-connected customers, and this lack of consensus makes it difficult for the OEB to make findings on this matter.

In the OEB's view, the record of this proceeding supports two very different conclusions on the issue of whether double-peak billing is a problem. The first possible conclusion is that double-peak billing is not a problem. This is because the ability to transfer load between delivery points to minimize costs associated with planned and unplanned outages confers benefits to a distribution utility or to a transmission-connected customer, and so the costs associated with a double-peak for the billing period during which the outage occurs are offset by the benefits of having a flexible and dynamic system.

Conversely, double-peak billing is a problem significant enough to warrant the establishment of a mechanism such as a deferral account to deal with the costs associated with the problem, although there may be more efficient methods than a deferral account to deal with the problem. Such alternatives were also proposed by the

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[25] OEB staff Reply Submission, p. 9
[26] Ibid.
[27] VECC Reply Submission, p. 5

parties, including changing the charge determinant for the rate pools and aggregating delivery points.

The OEB finds that it has not yet been established whether double-peak billing presents a significant or widespread problem for LDCs and transmission-connected customers. Once the scope and significance of the issue are better understood, the OEB can consider whether any identified problem warrants further action. This assessment would include determining whether the issue is limited to planned outages or also extends to unplanned outages.

Given the disparate views on this matter, the OEB finds it appropriate to convene a Working Group to examine the issue further. The Working Group, to be facilitated by OEB staff, should include representatives from transmitters, transmission-connected customers, and LDCs, ensuring a balanced representation of interests. The Working Group may not achieve consensus on all points but is tasked with gathering information, analyzing the issue, and providing recommendations on the following (non-exhaustive) list of questions by June 27th, 2025:

1. Whether double-peak billing is an issue with costs material enough to affected parties that a mechanism needs to be established to effectively deal with the problem.
2. If the answer to #1 above is yes, what mechanism(s) should be established to effectively deal with the problem? Such a mechanism could include, but may not be limited to, establishing a deferral account, changing charge determinants if feasible, or aggregating delivery points.
3. If double-peak billing is a problem, does the problem apply to both planned and unplanned outages?

The Working Group may also identify and make recommendations regarding other considerations relating to double-peak billing for UTRs. The OEB will review the Working Group's findings and determine the appropriate next steps.

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?

Only GCC submitted that changing the charge determinants to address double-peak billing would be an acceptable solution.[28] However, in doing so, GCC acknowledged the complexity of the undertaking and stated GCC's preference for other solutions, particularly, the deferral account considered under Issue 4.4.

HONI submitted that the nature of the historical data used to set the charge determinants is insufficient to distinguish double-peak billing events.[29] As a result, HONI would first need to establish the appropriate data set before such a change could be implemented. HONI also submitted that once the impact of transmission outages is removed from the charge determinants, the resultant rates would be increased as the same revenue requirement would be recovered. HONI also noted that the IESO would need to implement the new charge determinants into their settlement system.

VECC raised concern regarding the significant effort that this would involve and questioned whether a solution could be successfully implemented.[30] LPMA questioned whether sufficient information was available on the record to substantiate such a change.[31] AMPCO agreed with these submissions.[32]

OEB staff submitted that there is no issue with the charge determinants and that transmission outages should not be afforded special treatment.[33]

Findings

Because of the complexity of redefining the charge determinants noted by the IESO, and the possibility of dealing with double-peak billing costs via a deferral account, the OEB finds it unnecessary at this time to revise the definition of transmission charge determinants used to establish UTRs and bill transmission charges to specifically exclude the impact of planned outages for customers with load transfer capabilities between multiple delivery points. The OEB also notes that there was near unanimity

[28] GCC Submission, par. 10
[29] HONI Submission, p. 5
[30] VECC Submission, p. 8
[31] LPMA Submission, p. 5
[32] AMPCO Submission, p. 5
[33] OEB staff Submission, p. 8

among the parties that transmission charge determinants should not be changed at this time.

Issue 4.4: Should the double-peak billing impact of planned and unplanned transmission outages be tracked in a deferral account?

Except for OEB staff, all submissions favoured a deferral account to refund double-peak billing charges. While OEB staff did not oppose a deferral account solution, OEB staff questioned the appropriateness of such an account and raised concerns regarding the implementation of a deferral account to refund double-peak billing charges.

As noted under Issue 4.2, AMPCO, GCC, the LDC Transmission Group, LPMA, SEC, and VECC all submitted that double-peak billing due to transmission outages is unfair to transmission-connected customers. OEB staff only agreed that the situation identified by GCC, and only regarding the Network Service Charges, was unfair.

All submissions, including that of HONI, supported the deferral account solution on the basis that it could be the quickest and easiest to implement. These submissions also highlighted the transparency a deferral account approach would provide in relation to the double-peak billing impacts.

OEB staff submitted that, to establish a deferral account, the OEB's eligibility criteria of causation, materiality, and prudence should first be considered.[34] On causation, OEB staff noted the LDC Transmission Group's evidence detailed the operational steps that LDCs take to avoid double-peak billing. OEB staff questioned whether the materiality threshold would be met, as OEB staff asserted that HONI's Background Report demonstrates the impact of double-peak billing is immaterial to transmitters and double-peak billing costs are a pass-through for LDCs.[35]

In reply, HONI submitted that the OEB should not be restricted by the eligibility criteria given the context of the proceeding and goal of finding a solution to the double-peak billing issue.[36] Regardless, HONI examined the specific eligibility criteria, arguing that causation and materiality are met. HONI submitted that a working group set the details of the methodology to assure the OEB that the prudence criteria is met.

Several supporting submissions acknowledged that details need to be established. LPMA and VECC submitted that a working group should be formed to address and

[34] OEB staff Submission, p. 9
[35] OEB staff Submission, p. 10
[36] HONI Reply Submission, p. 8

resolve these outstanding issues. VECC submitted that the OEB should determine how to address situations with multiple transmission asset owners, such as when an LDC is partially embedded and served by a combination of transmission system and embedded distribution system connections.[37] VECC also submitted that the OEB establish criteria by which transmitters would demonstrate prudence in the management of transmission outages.

VECC and GCC also submitted that the double-peak billing costs are of a different nature than those normally subject to deferral account treatment. VECC submitted that materiality should be assessed from the perspective of the impacted transmission customer, and not from the perspective of the transmitter.[38] GCC suggested that double-peak billing refunds would be a cost that is arguably of a different nature from those costs habitually considered for deferral account treatment.[39] As a result, GCC submitted that it may not be appropriate to strictly apply materiality thresholds in the case of refunds that are designed to protect customers from unfairness.

Several submissions asserted that a solution for transmission-connected customers could also address the issues that exist in relation to distribution-connected customers. HONI also expected that the solution adopted by the OEB will eliminate the challenges associated with coordinating planned transmission outages while permitting transmitters to collect their OEB-approved revenue requirements.[40]

SEC, VECC, and the LDC Transmission Group all submitted that the OEB should consider how to extend any relief from double-peak billing to those customers who have a mix of transmission and distribution connections.[41]

OEB staff's concerns with a deferral account primarily focused on the interaction between this potential account and the two retail settlement variance accounts that relate to transmission charges paid by LDCs (the "RSVA accounts").[42] OEB staff expressed concern that refunds due to double-peak billing would introduce symmetrical and balancing amounts in the potential double-peak billing deferral account and the RSVA accounts. Any refund to an LDC for double-peak billing would be considered in the RSVA accounts, and the refund would be part of the transmitter's double-peak

[37] VECC Submission, p. 9
[38] VECC Reply Submission, p. 5
[39] GCC Reply Submission, par. 18
[40] HONI Submission, p. 9
[41] SEC Submission, p. 2, VECC Submission, p. 9, LDC Transmission Group Submission, p. 2
[42] OEB staff Reply Submission, p. 11

billing amount. OEB staff submitted that these refunds would require additional review, potentially disrupting the mechanistic nature of RSVA dispositions, which are intended to be straightforward.

Additionally, OEB staff raised the concern that if the disposition of the RSVA accounts were to be approved when there are unreviewed refunds, there could be a concern if the transmitter is unable to demonstrate prudence at the time it requests disposition of the double-peak billing deferral account.[43] If the OEB deems the refund to be imprudent, the LDCs would have received the benefit of the refund by virtue of their mechanistic disposition while the transmitter has the refund in the double-peak deferral account disallowed.

HONI also submitted that transmitters should be allowed to include the administrative cost associated with administering the account, including the determination of the double-peak billing refunds, as part of the double-peak billing deferral account.[44] OEB staff questioned whether it would be appropriate to introduce new costs that are unquantified and would subsequently be collected from all transmission customers.

Finally, OEB staff agreed with HONI regarding concerns that transmitters would take on a role within the settlement of transmission charges.[45] OEB staff raised concerns that introducing additional transactions from a new entity could cause confusion as this would result in the IESO and OEB having oversight over the settlement of transmission charges.[46]

Findings

The OEB notes that most parties expressed support for establishing a deferral account to track costs associated with double-peak billing. HONI also pointed out that there could be other associated operating costs from maintaining and tracking a deferral account. While OEB staff was not in favour of establishing a deferral account for the reasons discussed above and in the staff submission, OEB staff noted that it was not opposed to establishing a deferral account to deal with a potential double-peak billing problem.

[43] OEB staff Reply Submission, p. 12
[44] Ibid.
[45] OEB staff Reply Submission, p. 11, HONI Submission, p. 8
[46] OEB staff Reply Submission, p. 11

As noted in Issue 4.2, the OEB recognizes that there are several complex issues requiring further exploration and input from the parties before the OEB can consider and potentially approve the establishment of a deferral account. Many parties suggested that it would be appropriate for the OEB to establish a Working Group to sort out the details of the deferral account approach to mitigate double-peak billing costs. The OEB agrees and is establishing a Working Group pursuant to this Decision and Order (and discussed under Issue 4.2, above) to consider this matter. The OEB sees merit in receiving recommendations from the Working Group to better inform its decision into the issues related to mitigating double-peak billing costs.

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

In the Notice, Issue 5 is described as follows:

> The UTR establishes a gross load billing threshold of greater than 1 MW for non-renewable generating units and greater than 2 MW for renewable generating units for the transformation and connection rate pools paid for by transmission customers. The scope of this issue is to review whether the 1 MW and 2 MW thresholds are still the appropriate thresholds. The scope also includes considering the appropriate billing threshold for energy storage facilities. The scope of this issue does not include billing for distribution or whether energy storage facilities should be considered renewable or non-renewable (or something else) for purposes of gross load billing. The scope of this issue has been revised by the OEB from how it was first described in the October 15, 2021 Notice of Hearing for Phase 1 of the generic hearing on UTR-related issues.

Issue 5.1 contemplates whether the generating unit basis for applying the gross load billing threshold for the Line and Transformation Connection Charges should continue or be revised to a facility basis. Issue 5.2 contemplates the same question, specifically in the context of inverter-based embedded generation.

The HONI Background Report described pragmatic challenges with applying the UTR Terms and Conditions and undesirable or unintended customer behaviours resulting from the current structure of gross load billing. On both issues, the submissions were split.

Issue 5.3 contemplates how to apply the UTR schedule to energy storage facilities. Except for OEB staff, all submissions were focused on embedded energy storage and the gross load billing threshold for these facilities. In addition to considering gross load billing for embedded energy storage facilities, OEB staff also examined how the UTR schedule should apply to transmission-connected energy storage facilities.

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.

The submissions on this issue referred to following: the HONI Background Report; the impact of embedded generation on transmission planning and transmission ratepayers; and the basis on which the OEB established gross load billing in the original UTR proceeding. OEB staff put the greatest emphasis on the approach used by the OEB in the original UTR proceeding in examining the issue.

HONI emphasized that transmitters and their customers require clarification from the OEB to ensure consistent understanding of the UTR rules. HONI submitted that without clarification, there will continue to be customer dissatisfaction and complaints.[47]

APPrO/ESC, DRC, and ED submitted that the status quo – that is, the generating unit basis – should remain, generally submitting that a change would discourage new embedded generation and be contrary to the OEB's mandate and Provincial policy. HONI, SEC, and VECC argued for a facility basis, submitting that this reflected the impact of embedded generation to the transmission system and transmission system practices. OEB staff argued in favour of the status quo since the underlying generating unit basis had not been shown to be deficient, while also submitting that OEB staff does not oppose using a facility basis as the basis for defining the gross load billing threshold.

The HONI Background Report claimed that some commercial and industrial customers use the unit basis for gross load billing to install certain types of embedded generation so that they are exempt from gross load billing.[48] HONI submitted that the current structure provides exemptions based on the type of embedded generation and that this may not have been contemplated when the rules were established.[49] HONI suggested

[47] HONI Reply Submission, p. 13
[48] HONI Background Report, Issues 5 and 6, p. 6
[49] HONI Reply Submission, p. 13

this may be unfair and unreasonable. In HONI's view, a facility basis would address these concerns.

Both APPrO/ESC's and DRC's submissions challenged HONI's view that customer behaviour was driven by the structure of gross load billing. APPrO/ESC submitted that other reasons such as increased reliability and configuration constraints could motivate a customer to favour multiple units in selecting embedded generation.[50] DRC submitted that HONI failed to establish that the behaviour was intentional avoidance.[51]

APPrO/ESC and DRC also submitted that a change would discourage new embedded generation. APPrO/ESC argued that this would be contrary to the OEB's statutory objective to facilitate innovation.[52] DRC submitted there is value in the current approach to incentivize increased adoption of renewable embedded generation.[53]

VECC considered the customer's decision making and the OEB's statutory objectives. VECC agreed with HONI's submission and the HONI Background Report, submitting that the gross load billing rules should not influence a customer's decision regarding the technology or configuration of installed embedded generation.[54] VECC also submitted that the OEB Act no longer includes a statutory objective for the OEB to promote renewable generation, as it did when the OEB established the 2 MW gross load billing.[55]

HONI submitted that using the facility basis better reflects the cost impact of embedded generation to transmission ratepayers.[56] VECC's view was similar. VECC submitted that, for both connection impact assessments and transmission planning, the load at the connection point determines the level of transmission service.[57] Therefore, in VECC's view, this demonstrates that a facility basis reflects cost causality.

VECC and OEB staff considered the rationale for the gross load billing threshold in the original UTR proceeding. VECC submitted that the original basis for the 1 MW threshold

[50] APPrO/ESC Submission, pp. 2-3
[51] DRC Submission, par. 11
[52] APPrO/ESC Submission, p. 2
[53] DRC Submission, par. 9
[54] VECC Submission, p. 11
[55] The 2 MW gross load billing threshold was established in RP-2002-0120, proceeding pursuant to subsection 19(4), and 74 of the Ontario Energy Board Act, 1998 to review the Transmission System Code and Related Matters.
[56] HONI Submission, p. 10, lines 28-32
[57] VECC Submission, p. 13

is not germane to the issue.[58] VECC linked that decision's determination to electricity market dispatch and scheduling requirements, submitting that such requirements are not an important consideration to gross load billing.

In reply, OEB staff examined the context of the OEB's decision.[59] OEB staff noted that the decision in the original UTR proceeding established the 1 MW gross load billing threshold by accepting the applicant's proposal, where the applicant was HONI's predecessor, Ontario Hydro Networks Company Inc. OEB staff further examined that decision and submitted that the 1 MW threshold struck a balance between two considerations: the degree of cost shifting due to embedded generation and the costs of metering and billing that embedded generation.

OEB staff submitted that a prerequisite to considering a change from a unit to facility basis is to demonstrate that these two considerations have materially changed since the original UTR proceeding.[60] OEB staff submitted that the evidence had not shown a change since the original UTR proceeding and that the status quo had not been invalidated.

VECC, under Issue 6.1, identified cost-shifting as an important consideration for gross load billing, submitting that in its view, changes in gross load billing should consider the amount of revenue collected by gross load billing and the impact of change.

In arguing that gross load billing should be applied on a facility basis, SEC and VECC submitted that the OEB should consider a phase-in period and recognition of the existing facilities that were subject to gross load billing on a generating unit basis.[61] OEB staff submitted that if the OEB determines that billing should be on a facility basis, then this should trigger an evaluation of the level of the threshold.[62]

This issue also relates to the question of gross load billing thresholds and refurbishments. The HONI Background Report illustrated this question with an OEB staff response to an industry relation enquiry (IRE)[63] regarding the refurbishment of a load customer's pre-1998 four 800kW unit facility that would result in two new 2,000 kW

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58 Ibid.
59 OEB staff Reply Submission, pp. 6-7
60 OEB staff Reply Submission, p. 7
61 SEC Submission, p. 2, VECC Submission, p. 13
62 OEB staff Reply Submission, p. 5
63 Any OEB-licensed company, market participant, or other interested party may raise an issue or seek guidance on regulatory or policy obligations, among other things, by emailing the OEB. Further details regarding these types of enquiries to the OEB are available at https://www.oeb.ca/contact-ontario-energy-board#ire

units. In the response to the enquiry, OEB staff stated its view that in this case the gross load billing threshold should be applied on the total incremental capacity of the sum of the units.

HONI submitted that the application of the threshold should be consistent and not depend on whether the scenario involves new embedded generation or refurbishment of existing embedded generation.[64] OEB staff supported the facility basis from the IRE response by highlighting that the initiating enquiry began with the premise of a refurbishment that results in a change to the number of units at the facility. OEB staff submitted in this specific situation, the facility basis is appropriate.[65]

HONI further submitted that a refurbishment should trigger the need for the embedded generation facility to comply with the current rules, stating that this would be consistent with the IESO's enforcement of the Market Rules for grandfathered generation facilities.[66]

Findings

The OEB finds that this issue is fraught with policy considerations as well as fundamental rate-making principles. Many of the policy considerations have been brought out by the parties. DRC and APPrO/ESC have pointed to the energy transition realities that are currently upon us and the consequential need to continue to encourage embedded generation (particularly renewable generation), which favours continuing with the status quo of applying gross load billing on a unit basis.

Conversely, VECC noted that the OEB Act no longer includes any reference to cleaner energy sources as being among the OEB's objectives, and it is not the role of the OEB to set rates to incent broader societal interests (at the expense of consumers) unless it has specific direction to do so. VECC and HONI made arguments favouring changing the status quo to apply gross load billing on a facility basis.

HONI stated a strong desire for the OEB to clarify the application of gross load billing now rather than later. On the other hand, HONI has also noted that a broader and more comprehensive assessment of gross load billing is needed and that the OEB intends to undertake this detailed review in Phase 3 of this proceeding. HONI said that this would

[64] HONI Reply Submission, p. 14
[65] OEB staff Submission, p. 14
[66] HONI Submission, p. 11

be important and beneficial for a holistic exploration of the need for gross load billing and will require an in-depth examination into system planning practices.

The OEB agrees with OEB staff that the approach determined in RP-1999-0044 – the generating unit basis – has not been invalidated, and there has been no demonstration of a material change in cost shifting or administrative burden. Accordingly, the OEB finds it appropriate to continue with the status quo of determining gross load billing for embedded generating units on a unit basis, but notes that this issue must be examined as part of a comprehensive examination of gross load billing which the OEB may undertake at a later date.

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)?

The submissions on Issue 5.2 were generally consistent with those on Issue 5.1. DRC, ED, and OEB staff maintained their preference for the status quo, while HONI, SEC, and VECC were consistent in arguing for applying gross load billing thresholds on a facility basis for inverter-based embedded generation.

The HONI Background Report described the current practice of using the capacity of the inverter for each array or inverter set within an embedded solar generation facility to define an individual generator unit for applying the gross load billing threshold. HONI also stated that it applies the threshold using the 1 MW non-renewable threshold, and that the threshold is irrelevant as inverter capacity is typically less than 500 kW.

HONI stated this highlights an important need to review the applicable threshold as the current practice results in all embedded solar generation being exempt from gross load billing.[67] HONI stated that, in contrast, more than half the embedded wind generation capacity is billed on a gross load basis, as wind generating units tend to be greater than 2 MW.

It is HONI's view that the current application of the gross load billing threshold provides an exemption to solar generation facilities. HONI submitted that a change to a facility basis would rectify the advantage given to this type of generation.[68] HONI further submitted that if the OEB proceeds with a change, the OEB must consider how to apply

[67] HONI Submission, p. 11
[68] Ibid.

the threshold to existing solar facilities, arguing that gross load billing rules should not afford permanent exemptions.

HONI also submitted that embedded solar generation only applies to distribution customers.[69] HONI stated that as a result, if the OEB determines a gross load billing threshold that would result in gross load billing for these facilities, the OEB will need to issue guidance to distributors to clarify that these customers are responsible for paying the gross load billing costs and that those costs are not borne by other customers of the distributor.

HONI requested that the OEB provide clarity in this phase of the proceeding as to whether HONI should continue to use the inverter capacity for embedded solar generation facility to define an individual generating unit, or whether another practice is more technically suitable.[70] HONI requested there to be clear and unambiguous criteria.

VECC supported HONI's request that the OEB provide clarity. VECC submitted that if the OEB maintains the generating unit basis under Issue 5.1, it will be important for the OEB to confirm the appropriateness of applying this concept to the inverter capacity for inverter-based embedded generation. [71]

Findings

The OEB has considered HONI's view that the current application of the gross load billing threshold provides an exemption to solar facilities, and that the current application affords an inherent advantage to this type of generation. Nevertheless, for the following reasons, the OEB finds that, for now, the status quo should continue for embedded generation that employs inverters. The OEB's reasons for its findings on this issue can be summarized in four broad areas: 1.) Maximum Potential Grid Dependency; 2.) Alignment with Cost Causation; 3.) Consistency in Technical Standards and Grid Design; and 4.) Administrative Simplicity and Predictability.

Grid Dependency

Billing based on the inverter's capacity, rather than on a facility basis, ensures that the charges accurately reflect the embedded generator's maximum potential demand on the grid, even if it is infrequent. Inverters define the maximum instantaneous load that an embedded inverter-based generator could place on the transmission system during

[69] HONI Submission, p. 12
[70] HONI Reply Submission, p. 15
[71] VECC Submission, p. 14

times of insufficient output or equipment failure. Transmission systems must remain capable of supporting this maximum load to ensure grid reliability, even if the actual utilization is lower.

<u>Alignment with Cost Causation</u>

An inverter-based approach ties charges to the infrastructure needed to handle potential peak usage. Even embedded solar facilities that export power can occasionally act as net loads when solar generation is unavailable (for example, at night or during inclement weather). Billing on an inverter basis ensures that these generating units contribute fairly to the costs of maintaining a transmission system that can serve their full demand if needed.

<u>Consistency in Technical Standards and Grid Design</u>

Because inverters are a standard, measurable component of embedded generation systems, they provide a consistent basis for assessing potential grid impacts. Additionally, an inverter rating is a clear, quantifiable metric that simplifies the application of gross load billing, avoiding the complexities of tracking real-time net flows or highly variable operating conditions.

<u>Administrative Simplicity and Predictability</u>

Inverter-based gross load billing minimizes administrative complexity by avoiding the need for continuous measurement of real-time net load or complex net-metering adjustments.

Accordingly, the OEB finds that maintaining an inverter basis for a generation unit continues to be appropriate at this time. The OEB further notes that this concept may change following a comprehensive examination into the way distributed energy resources impact the system, which may occur in the future.

Issue 5.3: How should the UTR schedule apply to energy storage facilities?

All submissions examined this issue in the context of embedded energy storage facilities, while OEB staff also considered how the UTR schedule should apply to transmission-connected energy storage facilities.

For embedded energy storage facilities, APPrO/ESC, DRC, and ED primarily argued that these facilities should be exempt from gross load billing. These submissions argued for an exemption due to the benefits of these facilities as distributed energy resources. These submissions also raised concerns, stating that gross load billing would represent a barrier to wider adoption of energy storage facilities.[72] These submissions argued that such a barrier, and thus gross load billing, would contradict Provincial policy.[73]

APPrO/ESC took issue with the current transmission planning practice of assuming that no on-site generation will be available during peak demand hours.[74] APPrO/ESC submitted that this assumption contradicts the reason customers install energy storage, which serves the purposes of avoiding peak wholesale electricity market prices and reducing Global Adjustment charges.

VECC considered the issue in the context of transmission planning and submitted that embedded energy storage should be subject to gross load billing.[75] As noted in Issue 5.1, VECC submitted that the OEB's statutory objectives under the OEB Act no longer entail promoting certain technologies. As a result, VECC submitted that the UTR schedule should not favour certain technologies over others.

VECC also submitted that the relevant question regarding the benefits of energy storage is whether these facilities would lead to transmission facility savings.[76] VECC submitted that this is not the case and that the criteria for applying the UTR schedule must consider the cost implications to ratepayers and the impact on transmission system reliability.

OEB staff examined embedded energy storage in the context of the current UTR schedule and the proceeding that established the renewable embedded generation threshold.[77] The 2 MW per unit threshold for renewable generation installations was established to reflect the societal interest in increasing the proportion of renewable generation in the overall generation mix in the province and the technical reality that the output of some renewable source generation equipment has advanced from under the 1 MW per unit limit to just under 2 MW per unit.[78]

OEB staff submitted that embedded energy storage facilities are similarly in the societal interest as other renewable generation at the time of the proceeding that established the 2 MW per unit threshold.[79] Accordingly, OEB staff submitted that the gross load billing

[72] APPrO/ESC Submission, p. 3
[73] ED Submission, p. 1
[74] APPrO/ESC Reply Submission, p. 3
[75] VECC Submission, p. 15
[76] VECC Reply Submission, p. 11
[77] The 2 MW gross load billing threshold for renewable embedded generation was established in RP-2002-0120
[78] Decision with Reasons, RP-2002-0120, p. 43
[79] OEB staff Submission, p. 15

threshold for embedded energy storage should be the same as that of renewable embedded energy storage.

HONI submitted that the UTR schedules should not favour a particular technology over others. HONI expressed concern that if the UTR schedule does afford particular favour to certain technologies, this would lead to customers taking actions to avoid gross load billing.[80] HONI submitted that the gross load billing rules should be principles-based, considering how the facility is operated, the resultant impact on the customer's non-coincident peak demand, and the costs associated with implementing gross load billing.[81]

With respect to transmission-connected energy storage facilities, OEB staff considered this issue in the context of how these facilities operate in the electricity market, and thus the transmission system, and also how other jurisdictions treat these facilities.[82] On this basis, OEB staff submitted that transmission-connected energy storage facilities should be exempt from transmission charges under certain circumstances.

OEB staff submitted that the economic basis for operating a transmission-connected energy storage facility is the electricity market price arbitrage of withdrawing energy from the electricity system for later reinjection to supply that system. OEB staff argued that the nature of the price of electricity as a market commodity and the function of energy dispatches from the system operator mean that an energy storage facility would withdraw energy during times of low demand, and low transmission system load, to later discharge the stored energy during a time of high demand.

OEB staff submitted that the temporal nature of the Network Service Charge would naturally lead to conflict between the economics of the market or electricity load dispatches and the Network Service Charge. Furthermore, OEB staff argued that all transmission charges incurred in the process of charging an energy storage facility would be passed on to consumers in the form of fuel cost that would be incorporated into that facility's energy offers to the market.

As a result, OEB staff submitted that transmission-connected energy storage facilities should be exempt from transmission charges when following a load dispatch from the IESO in the real-time electricity market.[83]

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[80] HONI Submission, p. 13, lines 5-7
[81] HONI Submission, p. 13, lines 9-13
[82] OEB staff Submission, p. 16
[83] OEB staff Submission, p. 18

OEB staff also submitted: that transmission-connected energy storage facilities should be exempt when the facility is providing a transmission service to the IESO; that qualifying services should be those of operating reserve, frequency regulation, and voltage control; and that the exemption should also apply when a transmission-connected energy storage facility is called upon by the IESO for reliability.[84]

OEB staff submitted that the above exemptions would be entirely consistent with the treatment of these facilities in the Pennsylvania-New Jersey-Maryland Interconnection and Independent System Operator New England markets and, absent the exemption for real-time energy market dispatches, consistent with the New York Independent System Operator market.

Findings

The OEB is persuaded by OEB staff's assertion that energy storage facilities should be subject to gross load billing, and further that embedded energy storage facilities should be subject to the same threshold as renewable generation. OEB staff submitted that energy storage facilities are in the societal interest, and should be treated in a manner similar to that in which renewable generation was treated in RP-2002-0120, when the OEB established the 2 MW threshold, and the OEB accepts that notion.

With respect to transmission-connected energy storage facilities, the OEB notes that no party in its reply submission, save for OEB staff, considered how the UTR schedule should apply to transmission-connected energy storage. The OEB agrees with OEB staff that such facilities should be exempt from transmission service charges when these facilities provide physical services such as operating reserve, reactive power, or regulation service, or respond to real-time market dispatch signals or directives from the IESO in support of transmission system reliability. These facilities require energy withdrawals to provide these physical services and for their generation-related capabilities. Given the importance of these facilities to the system, it would be inappropriate to incorporate charges that signal otherwise. Therefore, an exemption from transmission service charges is practical when such facilities are called upon by the IESO.

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

In the Notice, Issue 6 is described as follows:

[84] OEB staff Submission, p. 18

> Beyond the question of appropriate gross load billing thresholds, set out in issue 5, there has been some uncertainty around the application of those thresholds to transmission customers – for example, with respect to incremental capacity resulting from a generator refurbishment. Clarification is currently provided to customers through OEB guidance..

In developing the issues list, the OEB combined the above issue with Issue 5.1. There are two sub-issues to Issue 6: what the gross load billing threshold should be and whether exemptions from the gross load billing threshold should be applied in certain circumstances. The sub-issues contemplate these questions for both renewable and non-renewable generation.

Issue 6.1: What should the gross load billing thresholds be for renewable and non-renewable embedded generation?

The UTR schedule establishes a gross load billing threshold of greater than 1 MW for non-renewable generating units and greater than 2 MW for renewable generating units for the line and transformation connection rate pools.

While the submissions on Issue 6.1 contained a mix of views, the majority concluded that the OEB should not make a change at this time. The most significant change was advocated by APPrO/ESC, submitting that, at a minimum, the threshold for non-renewable generating units should be increased to match that of renewable units; but ideally, that net load billing should be the norm.

DRC and ED submitted that gross load billing should support distributed or renewable generation. ED requested that the OEB not make changes without a deeper assessment at a future time. While VECC and SEC argued that there should only be one threshold, both also submitted that the OEB should consider those changes at a future time when more information is available. HONI did not take a position regarding the thresholds, but provided its perspective on the relevant considerations. OEB staff submitted that there was no basis to make a change at this time.

APPrO/ESC argued that both thresholds should be at least 2 MW, and that gross load billing should be the exception, not the rule.[85] APPrO/ESC argued that the current gross load billing policy is a barrier to on-site generation and implementing Provincial policy.

[85] APPrO/ESC Submission, p. 3

APPrO/ESC also took issue with HONI's practice to plan transmission system needs in order that the transmission system can supply all load served by on-site generation.[86]

VECC argued against APPrO/ESC's views by noting that the purpose of the thresholds was to reduce the administrative effort and costs associated with the settlement of transmission charges.[87]

DRC and ED shared APPrO/ESC's view that the gross load billing framework should promote and incentivize renewable distributed generation. DRC submitted that energy storage facilities that can be shown to support renewable generation more broadly should receive favourable treatment under the UTR schedule.[88] ED submitted that the Provincial government is calling for barriers to distributed energy resources to be removed. ED concluded by submitting that a broader assessment is required before making changes.[89]

VECC opposed DRC's view that the UTR schedule should favour embedded energy storage facilities, submitting that gross load billing thresholds should not be used as a tool to incentivize certain resources.[90] VECC's view is that the gross load billing rules should not influence a customer's decision as to the generation technology.[91]

Additionally, VECC argued that, absent a specific directive, transmission rates should reflect the costs of providing transmission service and not be used as a means to subsidize certain resources.[92] While VECC submitted that there no longer appears to be a need for different thresholds, VECC also submitted that there has been an insufficient exploration of the facts to make a change at this time.[93] SEC agreed with VECC.[94]

HONI identified several considerations it suggested would be important to the OEB regarding gross load billing thresholds.[95] These included the costs of metering equipment and the administrative effort of the IESO to incorporate that data into settlement processes and systems. HONI suggested the OEB should consider how

[86] APPrO/ESC Reply Submission, p. 3
[87] VECC Reply Submission, p. 12
[88] DRC Submission, par. 21
[89] ED Reply Submission, p. 2
[90] VECC Reply Submission, p. 10
[91] VECC Submission, p. 13
[92] VECC Reply Submission, p. 12
[93] VECC Submission, pp. 16-17
[94] SEC Submission, p. 3
[95] HONI Submission, pp. 13-14

changes in thresholds should be applied to existing embedded generation and that the OEB should strike a balance between fairness, practicality, and costs.

VECC also suggested several considerations for the OEB to consider.[96] These were administrative costs for settlement, metering costs, materiality of embedded generation in transmission planning, and revenue cost shifting.

Both HONI and OEB staff drew a linkage between the sub-issues to Issue 5 that considered the generating unit or facility basis for gross load billing and how that determination affects the level of the threshold.

Findings

The OEB will maintain the current gross load billing thresholds of greater than 1 MW for non-renewable generating units and greater than 2 MW for renewable generating units under the UTR schedule, as this balances fairness, practicality, and cost considerations, while aligning with established policy objectives.

The OEB notes that maintaining the status quo at this time also reflects most of the submissions from the stakeholders regarding the practicality and fairness of the current thresholds, and the view that transmission rates should reflect the cost of providing service rather than be used as tools to incentivize specific technologies.

Additionally, maintaining the current thresholds minimizes the administrative burden and costs associated with the settlement process. Changing the thresholds would increase metering and administrative complexity, potentially outweighing any benefits from incentivizing specific resources.

The OEB also notes that, while APPrO/ESC and DRC submitted that gross load billing thresholds should promote renewable generation, no specific directive from the Provincial government has been issued to mandate changes to the thresholds. The OEB finds that the current thresholds are consistent with the policy intent of supporting renewable generation while balancing system costs. Furthermore, the OEB notes that the current thresholds ensure that smaller renewable generators are shielded from gross load billing costs, which aligns with the objective of supporting distributed energy resources. Changes to the thresholds could introduce cost-shifting, impacting non-participating transmission customers, as noted by VECC and HONI.

[96] VECC Submission, p. 17

While the OEB finds that maintaining the status quo thresholds is appropriate at this time, the OEB acknowledges APPrO/ESC’s concerns about the gross load billing thresholds acting as a barrier to on-site generation and DRC’s submission that energy storage facilities that support renewable generation should receive favourable treatment. These concerns could merit further consideration should there be a comprehensive examination into how DERs impact the system. Clearly, if gross load billing thresholds are adjusted in the future, the OEB will then need to evaluate impacts on existing embedded generators, administrative costs, and revenue-cost shifting.

Issue 6.2: Should gross load billing exemptions be available in certain limited circumstances?

The HONI Background Report provided two situations that have raised the question of whether an exemption to gross load billing should be afforded to a transmission customer.

The first example was that of a customer increasing its load to a degree that exceeds the capacity of the transmission system that supplies that customer. To serve its load, the customer is installing embedded generation. Due to the size of the load, if gross load billing were applied as defined by the UTR schedule, the level of gross load billing would exceed the capacity of the lines that serve that load.

The second example was that of a customer installing embedded generation “for the sole purpose” of peak-shaving and mitigating Global Adjustment charges. In this scenario, the embedded generation is only used at select times to reduce the customer’s non-coincident peak lead.

All submissions argued in favour of gross load billing exemptions to some degree.

DRC took the view that there is merit in considering both examples from the HONI Background Report, while also submitting that exemptions should be limited to situations where the new or increasing load can be shown to contribute to renewable generation more broadly.[97] DRC argued that the exemptions should serve as an incentive to support decarbonization objectives.

ED submitted that exemptions should be allowed on a case-by-case basis in situations where the transmission system is constrained, with specific criteria.[98] ED made this submission on the basis of a HONI response to a clarifying question to the HONI

[97] DRC Submission, par. 35
[98] ED Submission p. 2

Background Report.[99] In that response, HONI referenced the examples summarized above from the HONI Background Report to agree there is merit in exemptions where the existing transmission system is unable to meet a customer's supply. HONI also stated in the response that if exemptions were pursued more generally within the regional planning process, the transmission customer would need to forego the originally built capacity that is displaced by the embedded generation.

VECC countered ED's submission on the basis that HONI's planning criteria for embedded generation will not make existing transmission capacity available to new load.[100]

VECC submitted that the first example in the HONI Background Report was that of an appropriate exemption.[101] OEB staff made the same submission.[102] Both viewed the exemption appropriate so that the level of gross load billing did not exceed the capability of the transmission system supplying the load.

VECC submitted that the second example was not an appropriate exemption.[103] As with the first example, OEB staff took the same position.[104] VECC argued that it would be difficult to ascertain the exact purpose of embedded generation and that the purpose could change over time.[105] Second, VECC questioned the materiality of the change in gross load billing amounts under this scenario. OEB staff submitted that this example was unrelated to the basis for gross load billing and that gross load billing should be applied as this would be aligned with the principle of recovering costs that could otherwise be stranded.

Finally, OEB staff submitted that the situation described by GCC was another example of a potential exemption to applying the UTR schedule.[106] GCC's situation was that double-peak billing occurred upon a load transfer to a secondary supply from HONI Distribution.

GCC submitted that its situation is discrete by the nature of its load transfer of all load to supply from HONI distribution.[107] OEB staff submitted that only the Network Service

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[99] HONI Clarifying Question Response, ED-1, part b)
[100] VECC Reply Submission, p. 13
[101] VECC Submission, p. 18
[102] OEB staff Submission, p. 20
[103] VECC Submission, p. 18
[104] OEB staff Submission, p. 20
[105] VECC Submission, p. 18
[106] OEB staff Reply Submission, pp. 9-10
[107] GCC Submission, par. 30

Charges were duplicative, and that the distribution Line and Transformation Connection Charges reflected GCC's usage of the distributor's assets. In reply, GCC submitted the duplicative Network Service Charge is unfair.[108] Since OEB staff did not view the other examples of double-peak billing as an issue, OEB staff recommended that GCC's scenario be considered for an exemption.

Findings

The OEB recognizes the evolving complexities associated with gross load billing and the need to consider specific exemptions under certain circumstances. As noted above, the HONI Background Report and various stakeholder submissions provided examples under which applying gross load billing in a strict manner under the UTR schedule may lead to unintended consequences or inefficiencies.

Further, GCC's submission highlighted a discrete situation involving double-peak billing upon transferring load to a secondary supply from HONI Distribution. OEB staff acknowledged the duplicative nature of Network Service Charges in this case but maintained that distribution Line and Transformation Connection Charges were appropriate. GCC contended that this duplicative Network Service Charge was unfair. The OEB agrees with staff's recommendation to evaluate this scenario for an exemption, given its distinct nature and potential fairness concerns.

The OEB proposes the following approaches to address the identified issues:

Case-by-Case Exemptions under Transmitter Licenses

Through a licence amendment, transmitters may seek exemptions from specific provisions in the OEB's regulatory instruments, including cost responsibility rules in the *Transmission System Code*. For example, a transmitter recently requested approval of an exemption to set a limit on the amount of capacity for gross load billing to address a customer's unique circumstances.[109] These applications must provide evidence supporting the need for an exemption, demonstrating alignment with system constraints and cost recovery principles.

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[108] GCC Reply Submission, par. 4
[109] The OEB received an application from Hydro One Sault Ste. Marie LP requesting a licence amendment for an exemption from section 4.2.2 of the Transmission System Code that would set a limit of 30 MW for gross load billing in relation to the Line Connection Service Charge to address the unique circumstances involving a transmission customer. This application is OEB file EB-2024-0357.

Further Considerations for the Working Group

The Working Group ordered by the OEB as part of Issue 4.2, should also examine and report back on gross load billing exemptions. The OEB suggests that the Working Group consider developing clear criteria for gross load billing exemptions, such as transmission system constraints or renewable generation support. Additionally, the Working Group should speak to fairness and cost recovery implications for unique cases, such as the double-peak billing scenario experienced by GCC.

Regional Planning Considerations

The Working Group may also consider addressing exemptions through the regional planning process, ensuring that transmission system upgrades, embedded generation, and customer load growth are holistically evaluated. Customers opting for embedded generation should forego the capacity initially built to serve their load, as noted by HONI, to ensure fair and efficient use of transmission resources.

In summary, the OEB supports a balanced approach to gross load billing exemptions, addressing technical constraints, fairness, and policy objectives, but will find on this issue after considering the recommendations from the Working Group.

4 IMPLEMENTATION

4.1 Implementation of Decision on Issue 4

As determined in the sub-issues of Issue 4, the OEB will establish a Working Group to report back to the OEB on certain elements of the double-peak billing issue. Additionally, this Working Group will consider certain aspects of Issue 6.2 as set out above.

The Working Group will report back to the OEB on the following questions:

1. Whether double-peak billing is an issue with costs material enough to affected parties that a mechanism needs to be established to effectively deal with the problem.
2. If the answer to #1 above is yes, what mechanism(s) should be established to effectively deal with the problem? Such a mechanism could include, but may not be limited to, establishing a deferral account, changing charge determinants if feasible, or aggregating delivery points.
3. If double-peak billing is a problem, does the problem arise in respect of both planned and unplanned outages?

The Working Group may also identify and make recommendations regarding other considerations relating to double-peak billing for UTRs. The Working Group should also examine and report back on gross load billing exemptions, considering criteria for gross load billing exemptions, such as transmission system constraints or renewable generation support. The Working Group should consider the fairness and cost recovery implications for unique cases, such as the double-peak billing scenario experienced by GCC.

4.2 Implementation of Decision on Issue 5

As determined under Issue 5.3, transmission-connected energy storage facilities shall be exempt from transmission charges under any of the following circumstances:

- When scheduled to provide operating reserve
- When providing reactive support
- When providing regulation service
- When responding to an IESO energy dispatch in the real-time electricity market
- When responding to an IESO directive in support of transmission system reliability

This exemption will be effective April 1, 2026.

The OEB directs OEB staff to work with the IESO, and any other necessary parties, to implement the above exemptions. This would include any necessary revisions to the UTR schedule and Terms and Conditions. The OEB anticipates that this implementation will also require material updates to the IESO's settlement systems and processes.

5 ORDER

THE ONTARIO ENERGY BOARD ORDERS THAT:

1. The OEB directs OEB staff to establish a Working Group composed of the interested parties to this proceeding to report back to the OEB by **June 27, 2025**, as to whether double peak billing is an issue with costs material enough to establish a mechanism to deal with the problem, what that mechanism should be, and whether that mechanism should apply to both planned and unplanned outages.

2. The Working Group shall also examine and report back on gross load billing exemptions and the criteria for those exemptions.

3. The OEB directs OEB staff to work with the IESO to coordinate the implementation of an exemption to transmission charges for transmission-connected energy storage facilities when these facilities are scheduled for operating reserve, providing reactive power support, providing regulation service, responding to a real-time IESO energy dispatch, or responding to an IESO reliability directive to begin effective April 1, 2026.

DATED at Toronto March 27, 2025

ONTARIO ENERGY BOARD

Nancy
Marconi

Digitally signed by Nancy
Marconi
Date: 2025.03.27
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Nancy Marconi
Registrar