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

DECISION AND RATE ORDER

EB-2022-0325

GENERIC HEARING ON UNIFORM TRANSMISSION RATES – PHASE 2

Decision and Order on Double-Peak Billing and Gross Load Billing Exemptions, Rate Order, and Order on Cost Awards

BEFORE: Pankaj Sardana
Presiding Commissioner

Fred Cass
Commissioner

Michael Janigan
Commissioner

November 27, 2025

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1 OVERVIEW

This proceeding is a generic hearing to consider various issues related to Ontario's Uniform Transmission Rates (UTRs). The generic hearing was initiated by the OEB and is now in its second phase. In this phase, the OEB is considering specific aspects of how transmission customers pay for their transmission service. They include matters such as how to reflect the time of the month when transmission customers connect to the transmission system; how transmission customers are charged when there is a transmission outage; and how to charge transmission customers who have embedded generation.

The OEB has already made decisions on many aspects of the issues in this proceeding. In its March 27, 2025, Decision, the OEB made determinations relating to planned transmission outages, electricity storage facilities, and how to treat embedded generation in a situation referred to as gross load billing. In making findings relating to transmission outages and gross load billing, the OEB recognized some questions remained. The OEB convened a Working Group to gather more information and make recommendations.

While this Decision also relates to other matters, this Decision is primarily the OEB's response to the Working Group's Report (the Report). The Report was filed on July 11, 2025, and made recommendations relating to refunds to certain customers due to transmission outages and exemptions to gross load billing.

This Decision adopts the recommendations of the Working Group by:

- Approving a deferral account for Transmitters to later recover refunds for double-peak billing events relating to planned transmission outages, and the administrative costs associated with determining and issuing those refunds.
- Approving sub-accounts to Retail Settlement Variance Accounts 1584 and 1586 for Distributors to record the refund amounts.
- Setting tiered minimum thresholds for double-peak billing refunds. The level of the threshold will be set by considering the size of the Distributor or whether the customer is a commercial or industrial transmission customer. For Distributors, the level will depend on the revenue requirement and the number of customers served. For other transmission customers, the level will depend on that customer's annual transmission charges.
- Tasking the Working Group with reconvening to develop proposals for determining double-peak billing refunds relating to unplanned transmission

outages and for a refund mechanism that can be extended to Distributors that are either partially or fully embedded within a host Distributor's system.
- Establishing criteria for granting gross load billing exemptions that are comprised of one mandatory requirement and a set of contextual considerations, such exemptions to be assessed, where practical, in conjunction with the Regional Planning process.
- Approving a pilot project exemption framework within the context of Regional Planning, subject to certain mandatory conditions, where embedded generation is located in transmission-constrained areas and the customer has agreed to forgo capacity.
- Approving gross load billing exemptions in cases where a customer's capacity needs exceed the available capacity on the transmission system, with associated revisions to the UTR Schedule that will be implemented in next UTR Rate Order.
- Establishing an interim remedy for Glencore Canada Corporation's Sudbury facilities to avoid the payment of duplicative network charges until a permanent solution to double-peak billing is implemented for all affected customers.

This Decision also sets a process for cost-eligible intervenors to file cost claims.

This Decision further confirms that the OEB has directed OEB staff to file proposed UTR Schedule amendments and any other considerations relating to the implementation of findings relating to electricity storage facilities from the March 27, 2025, Decision. The proposals will reflect the exemptions that are effective April 1, 2026. The OEB also expects any proposals to include any aspects relating to implementation for the OEB to consider. Parties to this proceeding will be provided the opportunity to comment on OEB staff's submission. The OEB will determine these, and any other relevant, procedural steps at the time OEB staff files this expected submission.

2 CONTEXT AND PROCESS

The 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.

The OEB issued a Notice of Hearing on October 27, 2023, identifying six issues in this proceeding. On May 9, 2024, the OEB rendered decisions on the timing of UTR rate order decisions, the number of decimal places for UTRs, and prorating transmission charges to account for when in the month a change in a connection took place.[1] The OEB also rendered a Decision on the implementation of prorating transmission charges.[2] This left Issues 4, 5 and 6 for determination at a later date. Issue 4 relates to the charges caused by transmission outages, which are termed "double-peak billing" charges. Issue 5 relates to the basis for billing renewable, non-renewable, and energy storage facilities. Issue 6 relates to gross load billing thresholds and exemptions to gross load billing.

With regard to Issues 4, 5, and 6, the OEB established a Working Group to gather information, analyze that information, and provide recommendations relating to double-peak billing and gross load billing exemptions.[3] [4] The OEB directed OEB staff to facilitate the Working Group. The Working Group filed its Report and provided several recommendations.[5]

The following parties were members of the Working Group:

- Association of Major Power Consumers of Ontario
- Distributed Resource Coalition
- Energy Probe Research Foundation
- Energy Storage Canada
- Entegrus Powerlines Inc.
- Environmental Defence Canada Inc.
- Glencore Canada Corporation (GCC)
- Hydro One Networks Inc. (HONI)

[1] Decision on Issues 1, 2, and 3, May 9, 2024
[2] Decision on Issue 3 Implementation, December 10, 2024
[3] Decision on Issues 4, 5, and 6, March 27, 2025
[4] OEB Letter accepting the representatives who will comprise the Working Group, April 29, 2025
[5] Working Group Report to the OEB, Recommendations relating to Double-Peak Billing and Exemptions to Gross Load Billing, July 11, 2025

- Independent Electricity System Operator (IESO)
- Niagara-on-the-Lake Hydro Inc.
- Vulnerable Energy Consumers Coalition

3 DECISION ON DOUBLE-PEAK BILLING

Issue 4 in this phase of the proceeding is Charges Caused by Planned Transmission Outages. The sub-issues considered different measures to address these charges and whether unplanned outages should be treated similarly to planned outages. In its findings on Issue 4 as part of the Decision on Issues 4, 5, and 6, the OEB noted disparate views on the matter and tasked the Working Group with reporting back on the following questions:

1. Whether double-peak billing is an issue that is material enough that a mechanism is needed to deal with the problem
2. If yes to the above, what mechanism or mechanisms should be established
3. If double-peak billing is a problem, whether the problem applies to both planned and unplanned outages

The Working Group stated that double-peak billing is a problem. The Report recommended that Transmitters issue refunds for double-peak billing impacts. The Report also recommended that the OEB establish a Transmitter-held deferral account for Transmitters. This account would allow Transmitters to later recover the refund amounts from all transmission customers. This account would also record the material administrative costs related to issuing refunds. The Working Group also requested additional time to further develop its recommendations to the OEB so that all transmission outages could be eligible for double-peak billing refunds. Further, the Working Group requested that the OEB affirm that embedded Distributors would also be eligible for double-peak billing refunds.

3.1 The Materiality of Double-Peak Billing

The Working Group reported that its members were unanimous in considering double-peak billing due to transmission outages to be a material issue. The Working Group defined double-peak billing as resulting from a customer's load transfer between multiple delivery points when:

(a) The delivery point from which the load was transferred still records its billing peak demand from the period without the load transfer, and
(b) The delivery point to which the load was transferred records its billing peak demand during the period the load transfer occurred.

The Working Group reported that the issue was material and pervasive. The Report stated that the double-peak billing charges, and customer action to avoid these charges, had operational impacts on planning and executing maintenance. Actions to avoid the charges result in transmission system configurations that could negatively affect the reliability of the system. The Working Group members also reported that double-peak billing was pervasive because these load transfers were expected to occur regularly and could affect any customer with more than one delivery point.

The Report also stated that, while load transfers were a normal aspect of operations, most Working Group members viewed double-peak billing due to outages for transmission system assets to be unfair. These members took this view on the basis that transmission customers were being charged twice for the same service. This view extended to embedded Distributors for outages outside their control.

Findings

The OEB agrees with the Working Group's assessment that double-peak billing due to transmission outages is both material and pervasive, with significant financial and operational impacts on customers. The OEB acknowledges that addressing this issue is essential to ensuring fairness and operational efficiency in Ontario's transmission system.

3.2 Planned and Unplanned Transmission Outages

On considering whether the problem applied to both planned and unplanned transmission outages, the Working Group reported that the availability of data to determine the incremental double-peak billing transmission charges was a prime consideration. The Working Group agreed that double-peak billing charges would occur during both planned and unplanned outages. The Working Group reported that its examination related to the challenges of establishing an objective, replicable, and auditable process for both categories of outages.

The Working Group members were unable to resolve these challenges within the provided time. The Report described key differences between planned and unplanned outages. These differences relate to the data that is available, how to establish a single-peak baseline for determining double-peak billing refunds, and how to determine how much load was transferred between delivery points.

The members identified several guiding principles:

- Completeness: Ensure refunds are based on accurate and verifiable information available to both the customer and the Transmitter.
- Consistency: Apply the same treatment to all customers, Distributors and commercial/industrial customers. Make sure refund methodologies are clearly defined and available to everyone.
- Compliance: Ensure compliance with Codes.

While the Working Group agreed the onus was on the transmission customer to fill any data gaps, there was disagreement regarding the estimation process to determine refunded amounts when there is insufficient data. With planned outages, pre-emptive steps can be taken to ensure the requisite data is collected. This may not be the case with unplanned outages. The Working Group requested additional time to examine the aspects specific to unplanned outages and situations that lack certain measured data. The Report also noted that disputes between Transmitters and their customers could arise if there was disagreement between the parties about the refund.

Coupled with the technical considerations, the Working Group acknowledged the administrative burden for Transmitters of issuing refunds. As a result, the Working Group recommended that Transmitters be compensated for these additional administrative costs.

Findings

The OEB agrees with the Working Group's findings that both planned and unplanned outages can result in double-peak billing charges. As noted above, the complexity of handling data discrepancies and the potential for disputes between Transmitters and their customers must be carefully considered in developing a consistent, fair, and transparent process for calculating refunds. The OEB accepts that a key challenge lies in establishing an objective, replicable, and auditable process to determine the incremental impact of an outage on transmission billing demand and any corresponding refund amount.

The OEB agrees that the principles of completeness, compliance, and consistency as described in the Report will guide the process for determining double-peak billing refunds. These refunds will use an established single-peak baseline and be determined with consideration for how much load is transferred between delivery points during the double-peak period.

The OEB finds that this process must balance the need for accuracy with the practical limitations of available data. The principles of completeness, consistency, and compliance will guide the development of this process:

- *Completeness* – refunds must be based on verifiable and transparent data available to both the Transmitter and the customer;
- *Consistency* – all customers and delivery points should be treated using the same methodology and assumptions; and
- *Compliance* – the process must align with applicable OEB Codes and Market Rules.

The OEB also recognizes the operational challenges involved in collecting and estimating data for unplanned outages, and that estimation methods may be necessary. For planned outages, advance scheduling and coordination may allow for more reliable measurement of transferred load. In either case, however, the OEB agrees that Transmitters should be compensated for the administrative burden associated with calculating and issuing refunds, particularly where estimation is required to address data gaps.

As noted above, though, further work will be necessary to develop a clear and objective methodology for refund calculations that can accommodate both planned and unplanned outages. The OEB recognizes that Transmitters may not be equipped to estimate wholesale meter readings. Further, establishing how much load has been transferred during a double-peak billing event may require more than estimating wholesale meter readings. The OEB agrees that establishing the single-peak baseline is important to a complete, consistent, and compliant process that is used to determine a double-peak billing refund. The OEB directs OEB Staff to continue facilitating the Working Group as it considers and proposes options to deal with double-peak billing related to unplanned outages in a complete, consistent, and compliant manner.

3.3 Threshold Test

Finally, the Report presented options for a threshold test for refunds. In one way, the threshold test was proposed to mitigate concerns relating to the administrative aspects of calculating refunds. The intention of a minimum threshold is to limit refunds to material double-peak billing impacts. In another way, there are concerns about fairness. There is recognition that materiality depends on the size of the customer.

A per-event threshold test was proposed. Some members preferred a minimum threshold based on revenue requirement. Other members thought the OEB's materiality threshold for cost-of-service applications was too restrictive for small Distributors and would be unfair. Two alternatives for these small Distributors were proposed: a lower revenue requirement threshold of $20,000 or a dollar-per-customer threshold. The Working Group did not have time to present a proposal for commercial and industrial transmission customers, but noted that no threshold, or a threshold based on percentage of annual transmission delivery costs, should be considered.

Findings

The OEB finds that the implementation of a threshold test for refunds is necessary to ensure an efficient, equitable, and administratively manageable process for addressing double-peak billing events resulting from transmission outages. To that end, the OEB will establish the following threshold framework:

- **Per-Event Minimum Threshold Requirement for affected Distributors:**

Refunds for double-peak billing from planned outages shall only be issued where the total impact exceeds a defined monetary threshold. The threshold shall apply on a per-event basis, rather than being aggregated across unrelated outages or billing periods.

For the purposes of this threshold, an *event* includes any continuous or reasonably contiguous period of planned outage activity, including instances of multiple outages occurring within a short time frame that are operationally or causally linked. This interpretation is intended to avoid artificial segmentation of outage events and to ensure fairness where intermittent outages may collectively contribute to a material billing impact.

The OEB will implement a tiered revenue requirement threshold structure, recognizing the differing capacities of Distributors based on size:

- For Distributors with an annual revenue requirement of $10 million or greater, a threshold of $50,000 per event shall apply.
- For those with an annual revenue requirement under $10 million, a lower threshold of $20,000 per event shall apply.
- For those with fewer than 10,000 customers, a threshold of 1% of the previous year's transmission charges shall apply.

This approach strikes a balance between administrative efficiency and fairness.

- **Commercial and Industrial Transmission Customers:**

The OEB acknowledges that the threshold test for large commercial and industrial transmission customers requires a tailored approach due to the scale and complexity of billing impacts. For these customers, refunds shall only be issued where the event impact exceeds 1% of the customer's previous year’s annual transmission delivery charges. In reconvening, the Working Group may recommend a further refinement through consultation with affected stakeholders.

Events falling below the applicable threshold shall not trigger a refund. Transmitters and Distributors shall retain documentation of such events for audit and compliance purposes.

The OEB concludes that the tiered threshold structure for Distributors is proportionate, scalable, and aligned with the objectives of regulatory efficiency, customer fairness, and utility capacity. Further, the OEB concludes that applying a threshold structure for commercial and industrial customers also meets these same objectives. It ensures that only material events trigger the administrative and financial costs of a refund process, while ensuring fairness for small Distributors.

3.4 The Deferral Account Mechanism

The Working Group supported a deferral account mechanism to facilitate Transmitter refunds for the incremental double-peak billing charges. The Report detailed several considerations for the Distributor’s and Transmitter’s accounting of the refunds, and the subsequent recouping of the refunded amount from all transmission customers.

On the Distributor side, the Distributor would collect the refund from its Transmitter to reduce the overall cost of receiving transmission service. To support this, the Working Group presented two options. One option was to establish sub-accounts under Retail Settlement Variance Accounts 1584 and 1586 to record the refunded amounts. The other option was to establish a dedicated Group 2 variance account for Distributors.

On the Transmitter side, after issuing a refund, the Transmitter would record that amount in a deferral account for later collection from all transmission customers. In addition to recouping the refund amount, the Transmitter would also receive additional revenue to cover the administrative costs associated with issuing the refunds. The Report recommended a newly created Group 2 deferral account to facilitate this, with a sub-account to record the administrative costs. The main account would record the sum of all issued refunds. While the Report favoured disposing of these balances at the time of the cost-of-service rebasing, the OEB notes that Transmitters could also seek disposition at the time of annual rate updates.

The Report identified the following information that a Transmitter would provide when seeking disposition of this account:

- Each of the three UTR charges would be tracked separately
- The account would track refunds issued to each Distributor, for each year
- The transmission customer who received the refund, including the month and year for each refund
- The incremental administrative costs would be tracked in a separate sub-account.

Additionally, the Report suggested that, when a Transmitter and its customer agree on the refund amount and its basis, the refunds are pass-through amounts similar to other transactions subject to the Group 1 retail settlement variance accounts (RSVAs). This means that the amounts refunded to Distributors would not require a prudence review when those Distributors seek clearance of their Group 1 accounts.

Findings

The OEB agrees with the Working Group's recommendation to establish a deferral account mechanism to facilitate the refunds of double-peak billing charges resulting from planned outages. This mechanism is crucial to ensuring that both Transmitters and Distributors can effectively manage the financial and administrative implications of issuing these refunds while maintaining transparency and fairness for all transmission customers.

The OEB also agrees with the Working Group's recommended reporting of the refunds. The Transmitter shall record refund amounts in a new Group 2 deferral account such that each refund is tracked by customer, showing the refund amount for each UTR charge. This deferral account will include a sub-account that separately tracks the incremental administrative cost of determining, documenting, and issuing refunds.

When a Transmitter brings amounts forward for disposition, the Transmitter will file, at minimum, the following information:

- The amount of the refund for each UTR charge
- The customer who received the refund
- The month and year of the outage, or contiguous set of outages, applicable to the refund

The OEB also supports the creation of sub-accounts under the Retail Settlement Variance Accounts 1584 and 1586 for Distributors to track received refunds.

This approach will allow for proper tracking, accounting, and recouping of refunds in a way that minimizes regulatory burden and administrative complexity. The OEB agrees with the Working Group that these refunds are pass-through transactions, as any other transactions for RSVA 1584 or 1586, when the Transmitter and the Distributor agree on the basis and the amount of the refund. For double-peak billing charges, the Distributor shall only record the agreed-upon refunded amount in these RSVA sub-accounts.

3.5 Additional Considerations

The Report also considered transmission service charges in the context of load transfers between transmission and embedded distribution delivery points. Load transfers of this kind would affect both UTR transmission service charges and Retail Transmission Service Charges relating to embedded distribution delivery points. The

Report noted that these also result in double-peak billing events, and that these events affect multiple parties. The Report stated that only a minority of Distributors are exclusively supplied by transmission delivery points. The majority have at least some connection to a host Distributor.

The Working Group submitted that these are important considerations. The Report requested that the OEB consider extending the deferral account mechanism to host Distributors. The Report also requested that the OEB task the Working Group with developing recommendations to address situations that affect embedded Distributors.

Findings

The OEB agrees with the Working Group's suggestion that load transfers between transmission-connected customers and embedded distribution delivery points result in double-peak billing events that affect multiple parties. These events highlight the need for a more coordinated and comprehensive approach to addressing double-peak billing across both transmission and distribution services.

The OEB supports the Working Group’s recommendation to extend the deferral account mechanism to host Distributors to ensure consistency and fairness in the treatment of refunds across the transmission and distribution system. The OEB also acknowledges the need for further work on the issues affecting embedded Distributors and will task the Working Group with developing additional recommendations to address their unique challenges in managing these complex billing scenarios.

The OEB asks OEB Staff to continue facilitating the Working Group so that it can develop a clear, equitable framework that ensures the efficient management of refunds for double-peak billing, while addressing the operational and administrative challenges faced by both large Distributors and embedded Distributors.

4 DECISION ON EXEMPTIONS – GROSS LOAD BILLING

As previously indicated in the Decision on Issues 4, 5, and 6, the OEB recognizes the evolving complexities associated with gross load billing and the need to consider specific exemptions under certain circumstances because strict application may lead to unintended consequences or inefficiencies. That Decision also discussed case-by-case exemptions that Transmitters may seek from specific provisions in the OEB's regulatory instruments and indicated such applications must provide evidence supporting the need for an exemption, as well as demonstrate alignment with system constraints and cost recovery principles.[6]

The OEB asked the Working Group to examine and report back on gross load billing exemptions in relation to the following:

- Develop clear criteria for gross load billing exemptions.[7]
- Consider addressing exemptions through the regional planning process for the purpose of "ensuring that transmission system upgrades, embedded generation, and customer load growth are holistically evaluated."[8]

The OEB also asked the Working Group to provide input on the following:[9]

- Evaluate the GCC scenario (described below in section 4.2.5) for an exemption, given its distinct nature and potential fairness concerns.
- Speak to the fairness and cost recovery implications for unique cases, such as the scenario experienced by GCC.

The OEB advised in its Decision on Issues 4, 5, and 6 that it would make its findings on the issues related to exemptions after considering the recommendations from the Working Group.[10] The Working Group's recommendations and the related OEB findings are set out below.

4.1 Criteria for Gross Load Billing Exemptions

The Working Group recommended a set of criteria for the purpose of determining whether a request for a gross load billing exemption is appropriate. Those criteria are comprised of one requirement and several considerations. The Working Group

[6] Decision on Issues 4, 5, and 6, EB-2022-0325, p.35
[7] Decision on Issues 4, 5, and 6, EB-2022-0325, p.36
[8] Ibid.
[9] Ibid.
[10] Ibid.

indicated that the recommended criteria for exemptions were informed by evaluating the scenarios that are discussed in this Decision. The recommended criteria are set out below beginning with the one requirement, which is as follows:

- Implementation of the exemption must not present any undue risk to the reliability and security of the transmission system, as determined by the IESO and the applicable Transmitter.

The Working Group recommended seven considerations to guide the assessment of gross load billing exemption requests. The Working Group further recommended that these considerations be balanced depending upon the specifics of the individual circumstance:

1. Demonstrates why an exemption is appropriate.
2. Provides appropriate flexibility to consider and address transmission system constraints.
3. Contributes to no or minimal risk of stranding assets.
4. Better achieves (or maintains) consistency with OEB cost responsibility principles (i.e., beneficiary pay, cost causality).
5. Results in treating customers more fairly in terms of cost recovery (i.e., avoids under- or over-charging and inappropriate cost shifting) for the transmission services received.
6. Contributes to transmission system cost minimization, including via price signals to encourage local generation in transmission constrained areas.
7. Implementation costs should be reasonable.

The Working Group indicated there were differing views related to the third criterion involving risk of stranded assets. While some Working Group members expressed the view that there should be “no” risk of stranded assets, the other members were of the view that “no” risk at all would set the bar too high and “no or minimal” risk should be sufficient (and the decision maker at the OEB should determine if the level of risk is acceptable).

Findings

The OEB finds that a structured, principle-based framework is necessary for assessing requests for exemptions from gross load billing. While exemptions should be limited to cases where they are clearly justified, the OEB recognizes that a rigid application of gross load billing in all cases can result in unintended inequities, inefficient cost recovery, and suboptimal system outcomes.

Accordingly, the OEB will adopt the following criteria for granting gross load billing exemptions:

1. Core Requirement (Mandatory Condition):

A gross load billing exemption shall not be granted unless the IESO and the applicable Transmitter confirm that the exemption does not present any undue risk to the reliability and security of the transmission system. This requirement must be satisfied in all exemption requests.

2. Balancing Considerations (Applied Case-by-Case):

Where the above reliability condition is met, the OEB will assess the exemption request against the seven considerations that were recommended by the Working Group. These are not standalone tests, but rather factors to be weighed together in light of the specific circumstances of each case:

1. **Justification**: The applicant must demonstrate a compelling rationale for the exemption, including why the standard application of gross load billing would be inappropriate.

2. **System Flexibility**: The exemption should provide flexibility to address system constraints without compromising broader reliability or planning objectives.

3. **Asset Stranding Risk**: The exemption should present no more than a minimal risk of creating stranded transmission assets. The OEB confirms that "no or minimal" risk is the appropriate standard, and rejects the view that "no risk" is a necessary threshold. The OEB retains discretion to assess whether the level of risk is acceptable in this context.

4. **Cost Responsibility Principles**: The exemption should support, or at minimum, not undermine the OEB's cost responsibility principles, including beneficiary pays and cost causality.

5. **Customer Fairness**: The exemption should enhance fairness in cost allocation, avoiding undue overcharging, undercharging, or cost shifting between customers.

6. **System Cost Minimization**: The exemption should contribute to the minimization of overall transmission costs, including through appropriate price signals (e.g., encouraging local generation in constrained areas).

7. **Reasonable Implementation Costs**: The implementation costs associated with the exemption must be reasonable and proportionate to the expected benefits.

3. Integration with Regional Planning:

Where practical, exemption requests should be assessed in conjunction with the regional planning process, to ensure alignment with long-term system planning, infrastructure development, and cost recovery objectives. However, the OEB will not delay consideration of an exemption solely to await the completion of a regional planning process.

This framework balances the need for consistency in the application of gross load billing with the flexibility to account for unique customer circumstances and system conditions. By adopting a clear mandatory requirement and a set of contextual considerations, the OEB ensures that exemptions are only granted where justified, where they do not undermine system reliability or cost fairness, and where they support efficient outcomes across Ontario's electricity system.

4.2 Evaluation of Exemption Scenarios

As noted above, the Working Group evaluated several scenarios including the two that were specifically requested in the Decision on Issues 4, 5, and 6 – Regional Planning Considerations and GCC – to assess the appropriateness of providing an exemption. Except for GCC, all the scenarios evaluated by the Working Group related to exemptions from full gross load billing. Other scenarios that were evaluated were referenced in the Decision on Issues 4, 5, and 6 and/or HONI's Background Report (for example, Transmission Capacity Constraints). Those scenarios were discussed by the Working Group during the meetings, and the recommendations are either based on consensus or were supported by a majority of the Working Group members. The Working Group's Report indicated two new scenarios were introduced after the Working Group meetings were held and the related recommendations were provided by a minority of members. One of those is referred to as "New Peak Shaving Embedded Generation scenario" while the other discusses a "Potential Comprehensive Assessment" of gross load billing.

4.2.1 Regional Planning Considerations Scenario

The Working Group recommended that an exemption should apply where the following conditions are met:

1. The embedded generation is located in a transmission constrained area, with such areas determined through a formal regional planning process;
2. The customer installing the embedded generation is required to forgo transmission capacity; and
3. The customer and Transmitter agree to a defined time period for the exemption and a solution that would ensure that the customer does not exceed its reduced capacity allocation.

The Working Group was of the view that this type of exemption would encourage non-wires investments to be located in areas of Ontario where they are most needed such as those that are transmission constrained (i.e., exemption would send a price signal) and it should result in a more efficient transmission system since it would facilitate the potential for new customers to connect to the grid without expanding the transmission system (i.e., Transmitter able to reallocate existing capacity of those customers that forgo capacity).

That said, the Working Group also recommended that, since this is a relatively complicated scenario because it would involve customers forgoing capacity, it should initially be implemented on a pilot project basis to allow for a thorough assessment of the potential implementation issues and inform how this type of exemption should be best considered as part of the regional planning process. It was also suggested that the pilot project be limited in scope (i.e., not open-ended) since the purpose is to assess implementation issues. As the Transmitter on the Working Group, HONI emphasized the need to first test this concept of customers forgoing capacity through a pilot project.

While there was a consensus on implementing a pilot project, some members expressed the view that the condition that embedded generation be required to be located in a transmission constrained area was not sufficient; rather, the embedded generation should need to be part of the solution that meets the regional need (i.e., addresses a specific transmission constraint).

Findings

The OEB finds that a narrowly scoped exemption from gross load billing is appropriate in the context of regional planning where embedded generation is located in transmission-constrained areas and the customer has agreed to forgo capacity. This targeted exemption is expected to support efficient use of existing transmission infrastructure, encourage non-wires solutions, and provide meaningful price signals to incent generation in areas of system need.

Accordingly, the OEB approves the implementation of a pilot project exemption framework (the Pilot), under which a limited number of projects may be approved for a gross load billing exemption subject to the following mandatory conditions:

1. Eligibility Criteria for Pilot Exemption

A gross load billing exemption under this pilot may be granted where all of the following conditions are satisfied:

a. **Location in a Transmission-Constrained Area**:
The embedded generation must be located in a formally identified transmission-constrained area, as determined through the regional planning process led by the IESO.

b. **Customer Agreement to Forgo Capacity**:
The customer must agree to contractually forgo transmission capacity, thereby enabling more efficient use of the local transmission system and freeing capacity for other customers.

c. **Defined Exemption Term and Enforcement Mechanism**:
The exemption must be limited to a specified duration and accompanied by a mechanism that ensures the customer does not exceed the agreed-upon capacity limit during the exemption period. This mechanism must be enforceable and accepted by the applicable Transmitter.

d. **Contribution to Addressing Regional Need**:
The OEB finds that mere location in a constrained area is not sufficient to justify an exemption. The embedded generation must contribute to addressing the identified constraint in the regional plan. Passive co-location in a constrained zone does not meet this standard.

2. Scope, Governance and Evaluation of the Pilot

The Pilot is intended to test the practical implementation of the proposed exemption framework and will be limited in scope.

- Participation is not automatic. The applicable Transmitter (on behalf of an individual project seeking an exemption under the Pilot) must apply to the OEB, and any exemption granted will be subject to OEB approval, based on whether the proposal satisfies all mandatory criteria and serves the objectives of the Pilot.

- The OEB anticipates that only a limited number of exemptions will be granted under this Pilot in order to enable meaningful evaluation and minimize risk of unintended consequences.
- The OEB may attach project-specific conditions as part of any approval under the Pilot.
- The results of the Pilot shall be evaluated based on:
  - Actual transmission capacity impacts;
  - Alignment with regional planning objectives;
  - Administrative and implementation challenges;
  - Customer cost impacts and fairness.

The results of the Pilot by the applicable Transmitter shall be reported to the OEB and will inform future determinations on whether such exemptions should be integrated into the broader gross load billing framework.

3. Oversight and Implementation

In implementing the Pilot, the OEB recognizes that effective oversight requires a clear division of responsibilities between operational execution and regulatory review. The Transmitter, supported by the IESO, will be responsible for designing, implementing, and evaluating the Pilot consistent with the parameters established by the OEB. The OEB's role is to approve pilot participation, establish the evaluation framework, and review the Transmitter's reported results to determine whether the exemption should be adopted more broadly. This approach ensures that the Pilot is informed by the operational expertise of sector participants while maintaining regulatory accountability and consistency with the OEB's policy objectives.

The OEB expects that the IESO and the applicable Transmitter will jointly oversee the technical and operational aspects of exemption's implementation, including enforcement of capacity limitations and confirmation that the embedded generation contributes to addressing the regional system need.

The Transmitter, with input from the IESO and participating customers, shall evaluate and report the Pilot results to the OEB in accordance with an evaluation framework established by the OEB. The evaluation should, at minimum, assess:

- the impact of the exemption on regional capacity utilization and reliability;
- the extent to which the embedded generation addressed the identified constraint;

- any cost or settlement implications; and
- administrative and implementation challenges encountered.

Upon receipt of the report, the OEB will review and assess the results to determine whether, and under what conditions, the exemption should be adopted more broadly within the regulatory framework.

The OEB will retain its regulatory oversight, including approval of Pilot participation and evaluation of outcomes. This ensures that the exemption supports system efficiency, cost-effectiveness, and fairness in cost responsibility. Linking the exemption directly to the regional planning process and requiring that the embedded generation be part of the solution, and not simply co-located, will avoid the risk of strategic siting that provides no actual system benefit.

The Pilot-based approach will allow the OEB and sector participants to assess real-world implementation issues without prematurely embedding a new exemption category into the regulatory framework.

4.2.2 Transmission Capacity Constraints Scenario

The Working Group recommended including an exemption in the UTR Rate Order that would apply where the customer's capacity needs exceed the available capacity on the Transmitter's transmission system. In such cases, gross load billing would continue to apply but it would be limited to the maximum capacity that can be supplied to the customer by the transmission system. The Working Group also recommended this exemption should be conditional on the Transmitter – and the IESO (where applicable) – completing the necessary technical assessments as a prerequisite. This recommendation was based on a consensus.

In its report, the Working Group discussed a recent OEB Decision issued under Delegated Authority that approved an exemption of this type.[11] The exemption was granted through a Hydro One Sault Ste. Marie (HOSSM) licence amendment, allowing HOSSM to bill Algoma Steel on only a portion of its capacity needs — specifically, 30 MW out of a total of 140 MW. This limitation reflected the maximum capacity that could be supplied by HOSSM's transmission system. HOSSM also indicated that the connection facility could not be upgraded.

[11] Decision & Order on Transmission System Code Exemption Related to Gross Load Billing, EB-2024-0357, May 6, 2025

The Working Group supported including the exemption in the UTR Rate Order since it would be relatively straightforward to implement. The Working Group noted that the wording for the “Terms and Conditions” section of the UTR Rate Order should not be overly restrictive (i.e., limited to the specific circumstances outlined in the HOSSM case). Instead, it should also account for other situations such as where the Transmitter can expand the system to meet the customer’s needs, but the timing does not align. This could arise, for example, where the customer’s new facility is expected to be in place in 18 months, and the Transmitter indicates that it can expand the system, but it will take five years to do so. In such a case, the Working Group suggested the exemption should be allowed during the five-year period until the Transmitter completes the expansion and is able to meet the customer’s full supply needs.

The Working Group also provided the following recommended wording for the UTR Rate Order in its Report.

> “Based on an assessment by the Transmitter (and the IESO, where applicable), where the transmission customer’s forecast capacity needs (associated with a new or modified load facility) exceed the maximum capacity that can be supplied by the transmission system and the licensed Transmitter cannot expand the transmission system to meet the transmission customer’s forecast capacity needs at the time the transmission customer’s load facility goes into service (and the transmission customer agrees to the maximum capacity allocated), the transmission customer shall be gross load billed for Line Connection service charges and Transformation Connection service charges, as appropriate, on only the maximum capacity that can be supplied by the transmission system. The application of gross load billing shall be adjusted by the Transmitter to the extent additional capacity can be allocated to meet the capacity needs associated with the transmission customer’s new or modified load facility.”

Findings

The OEB agrees with the Working Group’s recommendation to provide a gross load billing exemption in cases where a customer’s capacity needs exceed the available capacity on the transmission system. This exemption will ensure that gross load billing applies only to the maximum available capacity. It will be conditional on a technical assessment by the Transmitter and the IESO, where applicable, confirming the presence of system constraints.

The exemption will also apply in situations where a system upgrade is planned but not yet completed, ensuring that customers are not unfairly impacted by temporary capacity limitations.

The OEB finds it is appropriate to reflect this exemption in the UTR Rate Order. The OEB also finds that the recommended wording for the UTR Rate Order provides clear guidance on how these situations should be addressed, while allowing for sufficient flexibility to account for diverse system conditions.

To ensure consistent and transparent application of this exemption, the OEB expects that Transmitters will document the basis for each technical assessment supporting an exemption and make this information available to affected customers. OEB staff will monitor the implementation of this exemption through the rate order process and ongoing compliance oversight, and may bring forward any implementation concerns for the Board's consideration.

This approach provides clarity to stakeholders while allowing for a case-by-case assessment of technical limitations, consistent with the principles of fairness, efficiency, and transparency.

4.2.3 Industrial Conservation Initiative (ICI) related Scenario

The Working Group also discussed a scenario related to the ICI program that had been included in HONI's Background Report.[12] HONI had indicated an exemption may be warranted when a customer installs embedded generation for the sole purpose of peak shaving and mitigating their global adjustment (GA) charges because the embedded generation is only used at select times – about 20 times per year – to chase the "high 5" peaks under the ICI program.

The Working Group suggested that it is unlikely this type of exemption would pose a risk of bypass (and the stranding of assets), and it was also expected that it would result in a relatively immaterial reduction in transmission revenues.

However, due to the concerns discussed below, the Working Group recommended that the OEB not pursue this exemption at this time.

The Working Group indicated that a contentious aspect related to HONI's proposal was that, in HONI's view, metering of the embedded generation should not be required, as HONI wished to avoid imposing the related costs on ICI customers. Many members

[12] HONI UTR Phase 2 Background Report, p.14

expressed a concern that, in the absence of metering, there was no accurate way to ascertain if the embedded generation was actually only operating about 20 times per year, as HONI assumed.

Another concern identified by the Working Group related to the OEB previously indicating that this phase of the proceeding was focused on only the UTRs. As such, the exemption would be limited to transmission-connected ICI customers which would result in different treatment of ICI customers depending on whether they were connecting to the distribution system or the transmission system. There was a consensus that that outcome would not be acceptable and, if this exemption is adopted by the OEB, the Working Group expressed the view that it should apply to all ICI customers including those connecting to the distribution system.

A further Working Group concern was that the exemption would not be aligned with addressing transmission system constraints since ICI customers are located throughout the province, including areas where there is excess capacity on the transmission system.

Findings

While the Working Group acknowledged the minimal risks and potential benefits of the proposed exemption related to generation installed for the purpose of reducing GA charges, it ultimately recommended against proceeding with the exemption at this time. The OEB concurs with this recommendation.

The OEB finds that, although the exemption may offer benefits and does not pose significant risk, there are currently unresolved implementation issues. In particular, the need for a reliable metering solution to verify that the embedded generation is used solely for the intended purpose. Without such safeguards in place, granting the exemption now could undermine consistency and fairness in cost responsibility.

The OEB may be open to reconsidering this exemption in the future once more detailed assessments are completed and appropriate verification mechanisms are developed. At this time, however, the OEB will not allow this exemption.

4.2.4 Renewables Generation Support Scenario

The Working Group explained that, under this scenario, an exemption from gross load billing would apply to all renewable generation in the province regardless of where it is located. It was indicated that the primary rationale for this proposed exemption was to serve as an incentive to support decarbonization objectives.

The Working Group discussed the following statement in the OEB's Benefit-Cost Analysis Framework for Addressing Electricity System Needs[13]: "As stated in the [Framework for Energy Innovation] Report, it is not the role of the OEB to increase or accelerate [Non-Wire Solution] adoption, or to choose one technology solution over another." There were different interpretations of that statement among Working Group members. Some members interpreted it as intending to express that wires and NWS solutions should be assessed consistently. Other members interpret it as intending to relate to assessing all technologies consistently including among NWS options (i.e., "technology solution" not limited to wires vs. non-wires).

The Working Group concluded that this scenario should not be pursued due to a lack of agreement on the merits of such an exemption and whether it would be appropriate.

Findings

The OEB finds that the proposed exemption from gross load billing for all renewable generation in Ontario, regardless of location, should not be adopted. While the proposed exemption was intended to incent renewable generation and support broader decarbonization objectives, the OEB concludes that such a measure is not appropriate within the current regulatory framework. The OEB's Benefit-Cost Analysis Framework for Addressing Electricity System Needs (BCA Framework) emphasizes a technology-neutral approach, where all solutions — whether wires-based or NWS including renewable generation — are to be assessed consistently based on their cost-effectiveness and ability to address system needs.

The OEB recognizes that there were divergent views within the Working Group regarding the interpretation of the BCA Framework's guidance, particularly around whether the OEB's role includes supporting specific technologies to achieve policy goals. However, in the absence of a clear system need or demonstrable benefit to the transmission system, providing a blanket exemption for renewable generation would risk distorting cost allocation and undermine fairness.

Further, since no evidence was presented to suggest that a province-wide exemption for renewable generation would provide targeted or measurable relief to the transmission system or meaningfully contribute to reliability objectives, the proposed

[13] BCA Framework for Addressing Electricity System Needs, May 12, 2024, p.5

exemption could lead to unintended consequences, such as inequitable cost shifts among ratepayers or inefficient investment signals.

The OEB notes the importance of decarbonization and acknowledges that renewable generation plays a critical role in achieving long-term environmental and energy objectives. However, the appropriate tools to support such outcomes lie primarily in broader energy or climate policy frameworks, not through exemptions that conflict with the OEB's core regulatory principles.

Accordingly, the OEB agrees with the Working Group's recommendation and finds that the Renewables Generation Support Scenario will not be pursued further in the context of gross load billing reform.

4.2.5 GCC Scenario

As noted above, the Working Group was asked to evaluate the GCC scenario for an exemption (related to GCC paying duplicative transmission network charges) due to its distinct nature and potential fairness concerns.

The Working Group Report identified the following attributes associated with GCC in relation to its facilities in Sudbury.[14]

- "Transfers load from the connection on HONI Transmission to HONI Distribution (not between two transmission connections like typical double-peak billing).
- Network service charges are duplicative (i.e., does not involve Connection charges like typical double-peak billing).
- GCC's demand on the transmission system does not change though it pays separate Network charges to both HONI Transmission and HONI Distribution.
- Unlike GCC's facilities in Timmins (and most transmission connected customers), the transmission infrastructure was not sufficient to allow for a second transmission connection where GCC's Sudbury facilities are located.
- No investments have been made on HONI's distribution system for the purpose of accommodating GCC's load transfers.
- GCC's load transfers are only permitted if HONI Distribution has the necessary capacity available when GCC needs it."

[14] Working Group Report, p.32

Except for HONI, there was Working Group agreement that an exemption from the retail transmission service rate (RTSR) network charge would be appropriate to avoid GCC paying duplicative transmission network charges.

HONI expressed the view that GCC should be treated as part of the broader double-peak billing issue, rather than through an exemption. In response, GCC submitted that further deferral of addressing the fairness concerns to an undefined future process would result in continued payment of duplicative network charges and providing such an exemption need not preclude reviewing any solution currently adopted for GCC at the time of a broader review of double-peak billing issues.

The Working Group indicated that, if the OEB determines an exemption is appropriate, there was a consensus recommendation from an implementation perspective; that is, ensure HONI Distribution is held harmless by ultimately adopting the solution that is approved to address the broader double-peak billing issue (e.g., refund and deferral account) and apply it to GCC's situation, for consistency.

For the interim period, the Working Group provided three options for the OEB's consideration, as follows:

1. "Option 4" (in HONI's Background Report) where HONI Distribution would not bill the RTSR network charge to GCC and HONI Transmission would hold the deferral account;
2. Exempt HONI Distribution from paying – and charging GCC for – the portion of the network charge associated with GCC's demand. It was noted the IESO would need to further look into this option from an implementation perspective; and
3. Follow the IESO's existing Notice of Disagreement (NOD) process – HONI Distribution would submit a NOD to the IESO with supporting documentation on the double-peak event and the IESO would adjust the network charge determinant to exclude the impact resulting from the event, calculate the refund, and apply it to a future invoice of HONI Distribution.

The third option appeared to be favoured, as an interim approach, since the Working Group Report indicated GCC, the IESO and HONI were planning to discuss the potential for a pilot project to test it. It was also noted in the report that, under the NOD option, transmitters would not fully recover their OEB-approved revenue requirement due to the refund and, while it would not be a material issue for an exemption that is limited to GCC, it could become one if this exemption is extended to include a material number of other transmission customers in situations like GCC's.

Findings

The OEB finds that the circumstances associated with GCC's Sudbury facilities result in an inequitable outcome under current transmission billing practices. The OEB determines that GCC should be permanently exempt from paying duplicative network transmission charges for the same demand.

The OEB accepts the Working Group's assessment that GCC's situation is materially different from other double-peak billing cases and that further delay in addressing the fairness concern is unjustified. Unlike typical double-peak billing cases involving two transmission connections, GCC's load transfers occur between a transmission connection (HONI Transmission) and a distribution connection (HONI Distribution). These transfers do not increase GCC's overall demand on the transmission system, yet GCC currently pays duplicative network charges for the same demand — once through the IESO and again through HONI Distribution.

The OEB therefore determines that GCC shall be exempt from paying the RTSR network charge to HONI Distribution for its Sudbury facilities.

To implement this permanent exemption, the OEB directs that an interim settlement mechanism be used until a broader, permanent solution for double-peak billing (e.g., refund and deferral account framework) is established for all affected customers.

To ensure that HONI Distribution is held harmless from any financial impact of this exemption, the OEB directs that both of the following implementation mechanisms shall be put in place:

1. IESO's Notice of Disagreement (NOD) Process – HONI Distribution shall submit a Notice of Disagreement to the IESO, with supporting documentation, for each qualifying load-transfer event involving GCC. The IESO shall adjust the transmission network charge determinant to exclude the impact of the load transfer and apply the corresponding refund to a future invoice of HONI Distribution.
2. Deferral Account Tracking – The IESO shall track the value of any refunds provided to HONI Distribution under the NOD process in a notional deferral account. This account will ensure transparency and facilitate transition to the broader refund and deferral-account mechanism to be adopted as part of the OEB's final resolution of double-peak billing issues. The OEB notes the Working Group's finding that the amount of such a refund is **not material** for a single

customer exemption but a formal deferral account may become necessary if similar exemptions are extended to other customers.

The OEB directs the IESO, HONI Transmission, and HONI Distribution to work collaboratively to implement these measures promptly and to ensure that all relevant transactions are properly documented and auditable. The OEB is of the view that this approach provides GCC with permanent relief from duplicative transmission network charges for the same demand. This relief will be implemented through the temporary NOD and tracking mechanism until the OEB establishes a broader, permanent framework to address double-peak billing for all affected customers. The interim mechanism will hold HONI Distribution harmless, remain consistent with existing market and settlement rules, and ensure all relevant transactions are properly documented and auditable.

4.2.6 New Peak Shaving Embedded Generation Scenario

Some Working Group members recommended an exemption from gross load billing for all new embedded generation that is installed to offset some or all the peak demand arising from a customer’s new facility or an expansion to an existing facility. The example provided in the Working Group Report involved a customer with a 10 MW new load facility that installs 2 MW of embedded generation, such that the customer needs to request only 8 MW from the Transmitter.

The members that supported this exemption believe it would result in the following positive outcomes: increased fairness, cost minimization and efficiency, and empower consumers to invest in generation solutions tailored to their specific needs.

The Working Group indicated it did not have time to discuss this potential exemption as it was proposed after its meetings were concluded. However, concerns were expressed by several Working Group members, in written communications, which included the lack of a linkage to regional planning since the new embedded generation could be located anywhere in the province (i.e., may or may not be in a transmission-constrained area).

The Working Group members that support this potential exemption indicated they are only proposing that it be further explored if their proposed “comprehensive assessment” of gross load billing discussed below is not carried out as part of the next phase of this proceeding. In other words, if the OEB proceeds with that comprehensive assessment, this proposed exemption should be disregarded.

Findings

The OEB will not adopt the proposed exemption from gross load billing for new embedded generation installed to offset peak demand associated with new or expanded facilities at this time.

The proposal (put forward late in the Working Group process) suggests exempting embedded generation that reduces the net load of a new or expanded facility, on the basis that the customer's gross demand on the transmission system would be lower than it otherwise would be.

In making this finding, the OEB notes that the Working Group did not have an opportunity to evaluate or discuss this proposal in detail, including its practical implications, feasibility, or alignment with regional planning processes. Additionally, several Working Group members expressed concerns in written comments, particularly regarding the lack of locational specificity, that is, the prospect that embedded generation under this proposal could be installed in areas that do not face transmission constraints, thereby providing limited or no benefit to the broader system.

Lastly, the OEB notes that the proponents themselves indicated that this exemption need only be considered in the absence of a broader, more comprehensive assessment of gross load billing. The OEB finds that proposals of this nature are more appropriately considered within a broader policy framework, should one be initiated in the next phase of the UTR proceeding, where system-wide impacts, planning considerations, and cost responsibility principles can be fully assessed.

4.2.7 Potential Comprehensive Assessment

As noted above, some Working Group members recommended that the OEB undertake a comprehensive assessment of gross load billing because they are of the view that the generic exemptions – based on the scenarios discussed above that the Working Group has been able to arrive at – would not fully address the concern stated in the Decision on Issues 4, 5, and 6 that "applying gross load billing in a strict manner under the UTR schedule may lead to unintended consequences or inefficiencies".[15] Those members also noted that a "comprehensive examination into gross load billing" was identified

[15] Decision on Issues 4, 5, and 6, EB-2022-0325, p.35

among a list of matters by the OEB, in its Decision on Issues 4, 5, and 6, that may be considered by the OEB at a later date.[16]

The members also expressed the view that, although case-by-case exemptions and generic exemptions may improve system efficiency and fairness, they also have drawbacks such as: administrative and regulatory burden; few customers will qualify if exemptions are narrowly defined; the piecemeal nature of exemptions; and the requirement that exemption requests originate from the Transmitter (i.e., customer cannot request it).

In terms of scope, aside from a reference to "potential rate design reform" in the Working Group Report, those members did not indicate what a comprehensive review should entail. It was also noted in the Report that the Working Group did not have time to discuss the pros and cons of conducting a comprehensive assessment of gross load billing since the proposal was introduced after the Working Group meetings had been completed.

Findings

The OEB recognizes that there is considerable stakeholder interest in a more comprehensive review of gross load billing, including how it is applied, its alignment with cost responsibility principles, and the effectiveness of potential exemptions or reforms. A number of stakeholders raised questions about the fairness, efficiency, and transparency of the current gross load billing framework, particularly as it applies to customers with embedded generation, those subject to double-peak billing, and other non-wires solutions. Some Working Group members expressed that a broader, more holistic assessment of gross load billing could be valuable to ensure that it continues to support efficient system planning, fair cost recovery, and the evolving needs of electricity customers.

The OEB agrees that there may be merit in undertaking a comprehensive review of gross load billing in the future. Such a review could provide an opportunity to evaluate the current approach in a structured and coordinated manner, taking into account developments in distributed energy resources, decarbonization policy, system efficiency, and customer empowerment.

[16] Decision on Issues 4, 5, and 6, EB-2022-0325, p. 2

While the current proceeding has focused on specific scenarios and interim solutions, the OEB acknowledges the potential value of a more comprehensive assessment of gross load billing as a tool to support long-term system planning and rate design objectives. Any such review would benefit from broad stakeholder input and should be informed by practical experience gained through the implementation of near-term solutions.

At this time, the OEB is not making a determination on whether or when such a comprehensive review should take place but acknowledges that this is a matter that may warrant future consideration.

5 IMPLEMENTATION

5.1 Implementation of Double-Peak Billing Refunds

The OEB is establishing double-peak billing refunds related to transmission outages. The OEB approves these refunds for UTR charges for both Distributors and commercial & industrial customers. At this time, these refunds will be given in situations relating to planned transmission outages.

The refunds shall be treated as transactions between Transmitters and their customers. Where the customer is a Distributor, these refunds will be treated as commodity pass-through transactions. Refunds shall be calculated on the basis of a single-peak baseline. The OEB expects Transmitters and their customers to coordinate and collect all necessary information to ensure issued refunds adhere to the principles of completeness, consistency, and compliance.

The refunds shall be subject to a minimum threshold as follows:

- For Distributors with an annual revenue requirement of $10 million or greater, the minimum threshold is $50,000 per event
- For those with an annual revenue requirement under $10 million and with at least 10,000 customers, the minimum threshold is $20,000 per event
- For those with fewer than 10,000 customers, the minimum threshold is 1% of the previous year’s total transmission service charges per event
- For commercial and industrial customers, the minimum threshold is 1% of the previous year’s total transmission service charges per event

An event includes any continuous or reasonably contiguous period of planned outage activity, including instances of multiple outages occurring within a short time frame that are operationally or causally linked.

The OEB is establishing a Transmitter-held Double-Peak Billing Deferral Account. In this account, Transmitters will record the amounts for refunds that are issued to their customers. This account will also include a sub-account for Transmitters to record any material and incremental administrative costs associated with calculating and issuing the refunds.

The OEB is establishing RSVA 1584 and 1586 sub-accounts for Distributors to record the double-peak billing refunds. These accounts will record accrued refunds. These accrued refunds will only reflect agreed-upon refund amounts and there shall be no discrepancy as to the amount of the refund between the parties to the refund.

The effective date of these deferral and variance accounts will be January 1, 2026. The OEB will issue the Accounting Order in due course.

The OEB is continuing the Working Group. The Working Group is tasked with examining and proposing options for double-peak billing refunds that relate to unplanned outages. The OEB also recognizes that embedded Distributors are also affected by double-peak billing. The Working Group may also examine and propose options for calculating double-peak billing refunds to embedded Distributors. The proposed options will facilitate refunds for embedded Distributors without introducing unfair costs on the host Distributor.

OEB staff shall continue to facilitate the Working Group. Given the complexity of these issues and the need for sufficient analysis, the OEB is not establishing a timeline at this stage for a further report.

5.2 Implementation of Decision on Exemptions

As determined in section 4, the following shall be implemented:

- For the Regional Planning Considerations scenario, HONI Transmission shall design and implement a pilot project to assess the potential implementation issues associated with customers that install embedded generation in a transmission constrained area and forgo capacity. HONI Transmission shall inform all commercial and industrial customers that are connected to its transmission system of the Pilot once it is ready for implementation. HONI Transmission shall also prepare a report to the OEB on the results of the Pilot. If any other Transmitter implements the Pilot, the same obligations shall apply.

- In relation to the Transmission Capacity Constraints scenario, the “Terms and Conditions” section of the UTR Rate Order shall be amended by OEB staff to include an exemption from full gross load billing in relation to the applicable connection charges for cases where a customer’s capacity needs exceed the available capacity on the applicable transmission system (i.e., limit charges to the maximum capacity that can be supplied). In doing so, OEB staff shall use the wording recommended in the Working Group Report, with some minor revisions to achieve consistency with the terminology in the current UTR Rate Order and for clarity, which is set out in the next section of this Decision.

- For the GCC scenario, GCC shall be exempt from paying the RTSR network charge to HONI Distribution. To ensure HONI Distribution is not negatively impacted by the exemption, for the interim period – until a deferral account is established to address the broader double-peak billing issue – the IESO shall proceed with implementation of the NOD approach that involves adjusting the network charge determinant (when GCC has double-peak event) as described above, and a temporary and notional deferral account shall be established for the IESO in order to track the refunds provided to HONI Distribution for the network charges associated with GCC's demand previously charged to HONI Distribution.

The exemption associated with GCC will be effective on the date this Decision is issued. The exemption from full gross load billing, as set out in section 4.2.2 of this Decision, shall be effective on the date the amended UTR Rate Order is issued.

The OEB directs OEB staff to work with the IESO, and any other necessary parties, to implement the above exemptions. The OEB anticipates that this implementation will also require updates to the IESO's settlement systems and processes.

5.3 Cost Awards

Procedural Order No. 1 established the cost-eligible intervenors to this proceeding. Distributed Resource Coalition, Energy Storage Canada, and Environmental Defence applied for, and were granted, cost eligibility. Additionally, except for those who had written to the OEB to indicate otherwise, all parties from Phase 1[17] of this generic hearing were deemed intervenors in this proceeding. Phase 1 cost eligibility was also maintained.

The OEB has made provision in this Decision for these intervenors to file their cost claims.

[17] EB-2021-0243

6 ORDER

THE ONTARIO ENERGY BOARD ORDERS THAT:

1. The OEB directs OEB staff to continue facilitating the Working Group. The Working Group is tasked with developing proposals regarding double-peak billing refunds due to unplanned transmission outages. The Working Group is also tasked with examining options and developing proposals for a mechanism that will enable double-peak billing refunds for embedded Distributors.

2. OEB staff shall prepare an Accounting Order for the Double-Peak Billing Deferral and Variance Accounts in accordance with this Decision for issuance by the OEB at a later date.

3. The new paragraph set out below shall be incorporated into the Terms and Conditions of the Uniform Transmission Rate Schedule (after "Permanent Disconnection") and go into effect on the date this Decision and Order is issued to reflect the exemption from full gross load billing where a customer's capacity needs exceed the available capacity on the applicable transmission system.

    > Based on an assessment by the licensed transmission company (and the IESO, where applicable), where the Transmission Customer's forecast capacity needs (associated with a new or modified load facility) exceeds the maximum capacity that can be supplied by the transmission system and the licensed transmission company cannot expand the transmission system to meet the Transmission Customer's forecast capacity needs at the time the Transmission Customer's load facility goes into service (and the Transmission Customer agrees to limit its demand to the maximum capacity allocated), the Transmission Customer shall be subject to gross load billing for Line Connection service charges and Transformation Connection service charges, as appropriate, on only the maximum capacity that can be supplied by the transmission system. The application of gross load billing shall be adjusted by the licensed transmission company to the extent additional capacity can be allocated to meet the capacity needs associated with the Transmission Customer's new or modified load facility.

4. The IESO shall adjust the network charge determinant, calculate the refund, and apply it to a future invoice of Hydro One Distribution, when Glencore Canada Corporation has a double-peak event, based on supporting documentation provided

by Hydro One Distribution through the IESO's Notice of Disagreement process. The IESO shall also establish a notional deferral account on the date this Decision and Order is issued for the sole purpose of tracking any refunds provided to Hydro One Distribution.

5. Hydro One Transmission shall design and implement a pilot project in a manner that is consistent with the parameters set out in this Decision, including informing all commercial and industrial customers that are connected to its transmission system of the pilot project by June 1, 2026. Upon completion of the pilot project, Hydro One Transmission shall evaluate and report on the results to the OEB in accordance with the evaluation criteria set out in section 4.2.1 of this Decision.

6. Intervenors shall submit their cost claims to the OEB by **December 16, 2025**.

7. Rate-regulated electricity transmitters shall file with the OEB and forward to intervenors any objections to the claimed costs by **January 20, 2026.**

8. If a rate-regulated electricity transmitter objects to any intervenor costs, those intervenors shall file with the OEB and forward to all rate-regulated electricity transmitters their responses, if any, to the objections to cost claims on or before **January 27, 2026.**

9. Rate-regulated electricity transmitters shall pay the OEB's costs of, and incidental to, this proceeding upon receipt of the OEB's invoice.

DATED at Toronto November 27, 2025

ONTARIO ENERGY BOARD

Ritchie Murray

Digitally signed by Ritchie Murray
Date: 2025.11.27 15:38:47 -05'00'

Ritchie Murray
Acting Registrar

SCHEDULE A
GENERIC HEARING ON UNIFORM TRANSMISSION RATES
PHASE 2
EB-2022-0325

2025 ONTARIO UNIFORM TRANSMISSION RATE SCHEDULES

EB-2024-0244

The rates contained herein shall be implemented effective January 1, 2025.

The provisions of Paragraph (N) of the Terms and Conditions contained herein shall be implemented effective November 27, 2025.

Issued: November 27, 2025

Ontario Energy Board

TERMS AND CONDITIONS

(A) APPLICABILITY The rate schedules contained herein pertain to the transmission service applicable to:

• The provision of Provincial Transmission Service (PTS) to the Transmission Customers who are defined as the entities that withdraw electricity directly from the transmission system in the province of Ontario.

• The provision of Export Transmission Service (ETS) to electricity market participants that export electricity to points outside Ontario utilizing the transmission system in the province of Ontario. The Rate Schedule ETS applies to the wholesale market participants who utilize the Export Service in accordance with the Market Rules of the Ontario Electricity Market, referred to hereafter as Market Rules. These rate schedules do not apply to the distribution services provided by any distributors in Ontario, nor to the purchase of energy, hourly uplift, ancillary services or any other charges that may be applicable in electricity markets administered by the Independent Electricity System Operator (IESO) of Ontario.

(B) TRANSMISSION SYSTEM CODE The transmission service provided under these rate schedules is in accordance with the Transmission System Code (Code) issued by the Ontario Energy Board (OEB). The Code sets out the requirements, standards, terms and conditions of the transmitter's obligation to offer to connect to, and maintain the operation of, the transmission system. The Code also sets out the requirements, standards, terms and conditions under which a Transmission Customer may connect to, and remain connected to, the transmission system. The Code stipulates that a transmitter shall connect new customers, and continue to offer transmission services to existing customers, subject to a Connection Agreement between the customer and a transmitter.

(C) TRANSMISSION DELIVERY POINT The Transmission Delivery Point is defined as the transformation station, owned by a transmission company or by the Transmission Customer, which steps down the voltage from above 50 kV to below 50 kV and which connects the customer to the transmission system. The demand registered by two or more meters at any one delivery point shall be aggregated for the purpose of assessing transmission charges at that delivery point if the corresponding distribution feeders from that delivery point, or the plants taking power from that delivery point, are owned by the same entity within the meaning of Ontario's *Business Corporations Act*. The billing demand supplied from the transmission system shall be adjusted for losses, as appropriate, to the Transmission Point of Settlement, which shall be the high voltage side of the transformer that steps down the voltage from above 50 kV to below 50 kV.

(D) TRANSMISSION SERVICE POOLS The transmission facilities owned by the licensed transmission companies are categorized into three functional pools. The transmission lines that are used for the common benefit of all customers are categorized as Network Lines and the corresponding terminating facilities are Network Stations. These facilities make up the Network Pool. The transformation station facilities that step down the voltage from above 50 kV to below 50 kV are categorized as the Transformation Connection Pool. Other electrical facilities (i.e. that are neither Network nor Transformation) are categorized as the Line Connection Pool. All PTS customers incur charges based on the Network Service Rate (PTS-N) of Rate Schedule PTS. The PTS customers that utilize transformation connection assets owned by a licensed transmission company also incur charges based on the Transformation Connection Service Rate (PTS-T). The customer demand supplied from a transmission delivery point will not incur transformation connection service charges if a customer fully owns all transformation connection assets associated with that transmission delivery point. The PTS customers that utilize lines owned by a licensed transmission company to connect to Network Station(s) also incur charges based on the Line Connection Service Rate (PTS-L). The customer demand supplied from a transmission delivery point will not incur line connection service charges if a customer fully owns all line connection assets connecting that delivery point to a Network Station. Similarly, the customer demand will not incur line connection service charges for demand at a transmission delivery point located at a Network Station.

(E) MARKET RULES The IESO will provide transmission service utilizing the facilities owned by the licensed transmission companies in Ontario in accordance with the Market Rules. The Market Rules and appropriate Market Manuals define the procedures and processes under which the transmission service is provided in real or operating time (on an hourly basis) as well as service billing and settlement processes for transmission service charges based on rate schedules contained herein.

(F) METERING REQUIREMENTS In accordance with Market Rules and the Transmission System Code, the transmission service charges payable by Transmission Customers shall be collected by the IESO. The IESO will utilize Registered Wholesale Meters and a Metering Registry in order to calculate the monthly transmission service charges payable by the Transmission Customers. Every Transmission Customer shall ensure that each metering installation in respect of which the customer has an obligation to pay transmission service charges arising from the Rate Schedule PTS shall satisfy the Wholesale Metering requirements and associated obligations specified in Chapter 6 of the Market Rules, including the appendices therein, whether or not the subject meter installation is required for settlement purposes in the IESO-administered energy market. A meter installation required for the settlement of charges in the IESO-administered energy market may be used for the settlement of transmission service charges. The Transmission Customer shall provide to the IESO data required to maintain the information for the Registered Wholesale Meters and the Metering Registry pertaining to the metering installations with respect to which the Transmission Customers have an obligation to pay transmission charges in accordance with Rate Schedule PTS. The Metering Registry for metering installations required for the calculation of transmission charges shall be maintained in accordance with Chapter 6 of the Market Rules. The Transmission Customers, or Transmission Customer Agents if designated by the Transmission Customers, associated with each Transmission Delivery Point will be identified as Metered Market Participants within the IESO's Metering Registry. The metering data recorded in the Metering Registry shall be used as the basis for the calculation of transmission charges on the settlement statement for the Transmission Customers identified as the Metered Market Participants for each Transmission Delivery Point. The Metering Registry for metering installations required for calculation of transmission charges shall also indicate whether or not the demand associated with specific Transmission Delivery Point(s) to which a Transmission Customer is connected attracts Line and/or Transformation Connection Service Charges. This information shall be consistent with the Connection Agreement between the Transmission Customer and the licensed Transmission Company that connects the customer to the IESO-Controlled Grid.

(G) EMBEDDED GENERATION The Transmission Customers shall ensure conformance of Registered Wholesale Meters in accordance with Chapter 6 of Market Rules, including Metering Registry obligations, with respect to metering installations for embedded generation that is located behind the metering installation that measures the net demand taken from the transmission system if (a) the required approvals for such generation are obtained after October 30, 1998; and (b) the generator unit rating is 2 MW or higher for renewable generation and 1 MW or higher for non-renewable generation; and (c) the Transmission Delivery Point through which the generator is connected to the transmission system attracts Line or Transformation Connection Service charges. These terms and conditions also apply to the incremental capacity associated with any refurbishments approved after October 30, 1998, to a generator unit that was connected through an eligible Transmission Delivery Point on or prior to October 30, 1998, and the approved incremental capacity is 2 MW or higher for renewable generation and 1 MW or higher for non-renewable generation. The term renewable generation refers to a facility that generates electricity from the following sources: wind, solar, biomass, bio-oil, biogas, landfill gas, or water. Accordingly, the distributors that are Transmission Customers shall ensure that connection agreements between them and the generators, load customers, and embedded distributors connected to their distribution system have provisions requiring the Transmission Customer to satisfy the requirements for Registered Wholesale Meters and Metering Registry for such embedded generation even if the subject embedded generator(s) do not participate in the IESO-administered energy markets.

(H) EMBEDDED CONNECTION POINT In accordance with Chapter 6 of the Market Rules, the IESO may permit a Metered Market Participant, as defined in the Market Rules, to register a metering installation that is located at the embedded connection point for the purpose of recording transactions in the IESO-administered markets. (The Market Rules define an embedded connection point as a point of connection between load or generation facility and distribution system). In special situations, a metering installation at the embedded connection point that is used to settle energy market charges may also be used to settle transmission service charges, if there is no metering installation at the point of connection of a distribution feeder to the

Transmission Delivery Point. In the above situations:

• The Transmission Customer may utilize the metering installation at the embedded connection point, including all embedded generation and load connected to that point, to satisfy the requirements described in Section (F) above provided that the same metering installation is also used to satisfy the requirement for energy transactions in the IESO-administered market.

• The Transmission Customer shall provide the Metering Registry information for the metering installation at the embedded connection point, including all embedded generation and load connected to that point, in accordance with the requirements described in Section (F) above so that the IESO can calculate the monthly transmission service charges payable by the Transmission Customer.

(I) COME INTO SERVICE has the meaning given to that term in the Code.

(J) CUSTOMER FACILITIES A Transmission Customer's equipment, elements, and facilities of any kind whatsoever that are relevant to a direct connection to the transmission system at a Transmission Delivery Point where the Transmission Customer uses transformation connection assets owned by a licensed transmission company and/or line connection assets owned by a licensed transmission company.

(K) CHANGE IN OWNERSHIP When an existing Transmission Customer (the transferor) transfers the title of a load facility to a new customer (transferee), as provided in written notice to the applicable transmitter and the IESO, by the transferee.

(L) NEW CONNECTION Where new Customer Facilities will be directly connected to the transmission system at a Transmission Delivery Point and energized following commissioning.

(M) PERMANENT DISCONNECTION Where Customer Facilities are permanently disconnected from the transmission system in accordance with Section 20.1 or 20.3.1 and subject to Section 20.5 of the form of Connection Agreement applicable to the Transmission Customer in Appendix 1 to the Code.

(N) EXEMPTION Based on an assessment by the licensed transmission company (and the IESO, where applicable), where the Transmission Customer's forecast capacity needs (associated with a new or modified load facility) exceeds the maximum capacity that can be supplied by the transmission system and the licensed transmission company cannot expand the transmission system to meet the Transmission Customer's forecast capacity needs at the time the Transmission Customer's load facility goes into service (and the Transmission Customer agrees to limit its demand to the maximum capacity allocated), the Transmission Customer shall be subject to gross load billing for Line Connection service charges and Transformation Connection service charges, as appropriate, on only the maximum capacity that can be supplied by the transmission system. The application of gross load billing shall be adjusted by the licensed transmission company to the extent additional capacity can be allocated to meet the capacity needs associated with the Transmission Customer's new or modified load facility.

APPLICABILITY:

The Provincial Transmission Service (PTS) is applicable to all Transmission Customers in Ontario who own facilities that are directly connected to the transmission system in Ontario and that withdraw electricity from this system.

	Monthly Rate ($ per kW)
Network Service Rate (PTS-N):	**6.37**
$ Per kW of Network Billing Demand [1,2]	
Line Connection Service Rate (PTS-L):	**1.00**
$ Per kW of Line Connection Billing Demand [1,3,4]	
Transformation Connection Service Rate (PTS-T):	**3.39**
$ Per kW of Transformation Connection Billing Demand [1,3,4,5]	

The rates quoted above shall be subject to adjustments with the approval of the Ontario Energy Board.

Notes:

1. The demand (MW) for the purpose of this rate schedule is measured as the energy consumed during the clock hour, on a "Per Transmission Delivery Point" basis. The billing demand supplied from the transmission system shall be adjusted for losses, as appropriate, to the Transmission Point of Settlement, which shall be the high voltage side of the transformer that steps down the voltage from above 50 kV to below 50 kV at the Transmission Delivery Point.

2. The Network Service Billing Demand is defined as the higher of (a) customer Coincident peak demand (MW) in the hour of the month when the total hourly demand of all PTS customers is highest for the month, and (b) 85 % of the customer peak demand in any hour during the peak period 7 AM to 7 PM (local time) on weekdays, excluding the holidays as defined by IESO. The peak period hours will be between 0700 hours to 1900 hours Eastern Standard Time during winter (i.e. during standard time) and 0600 hours to 1800 hours Eastern Standard Time during summer (i.e. during daylight savings time), in conformance with the meter time standard used by the IESO settlement systems.

3. The Billing Demand for Line and Transformation Connection Services is defined as the Non-Coincident Peak demand (MW) in any hour of the month. The customer demand in any hour is the sum of (a) the loss-adjusted demand supplied from the transmission system plus (b) the demand that is supplied by an embedded generator unit for which the required government approvals are obtained after October 30, 1998 and which have installed capacity of 2 MW or more for renewable generation and 1 MW or higher for non-renewable generation on the demand supplied by the incremental capacity associated with a refurbishment approved after October 30, 1998, to a generator unit that existed on or prior to October 30, 1998. The term renewable generation refers to a facility that generates electricity from the following sources: wind, solar, biomass, bio-oil, biogas, landfill gas, or water. The demand supplied by embedded generation will not be adjusted for losses.

4. Upon a New Connection, Permanent Disconnection, or Change in Ownership, the total monthly charge for each of the Line Connection Service and the Transformation Connection Service will be prorated. The proration shall be based on the total monthly charge for each service and the applicable number of days of the month using the come into service date for a New Connection, the date of the Permanent Disconnection, or the date of the Change in Ownership of Customer Facilities as identified in an agreement where the transmitter consents to the assignment of the Transmission Connection Agreement by the transferor to the transferee, whichever is applicable.

5. The Transformation Connection rate includes recovery for OEB approved Low Voltage Switchgear compensation for Toronto Hydro Electric System Limited and Hydro Ottawa Limited.

TERMS AND CONDITIONS OF SERVICE:

The attached Terms and Conditions pertaining to the Transmission Rate Schedules, the relevant provisions of the Transmission System Code, in particular the Connection Agreement as per Appendix 1 of the Transmission System Code, and the Market Rules for the Ontario Electricity Market shall apply, as contemplated therein, to services provided under this Rate Schedule.

RATE SCHEDULE: (ETS) EXPORT TRANSMISSION SERVICE

APPLICABILITY:

The Export Transmission Service is applicable for the use of the transmission system in Ontario to deliver electrical energy to locations external to the Province of Ontario, irrespective of whether this energy is supplied from generating sources within or outside Ontario.

	Hourly Rate
Export Transmission Service Rate (ETS):	$1.86 / MWh

The ETS rate shall be applied to the export transactions in the Interchange Schedule Data as per the Market Rules for Ontario's Electricity Market. The ETS rate shall be subject to adjustments with the approval of the Ontario Energy Board.

TERMS AND CONDITIONS OF SERVICE:

The attached Terms and Conditions pertaining to the Transmission Rate Schedules, the relevant provisions of the Transmission System Code and the Market Rules for the Ontario Electricity Market shall apply, as contemplated therein, to service provided under this Rate Schedule.