# Working Group Report to the OEB

# Uniform Transmission Rates (UTR) – Phase 2

## Recommendations relating to

## Double-Peak Billing and Exemptions to Gross Load Billing

**Prepared by the UTR Phase 2 Working Group**

**EB-2022-0325**

**July 11, 2025**

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## CONTEXT AND PROCESS

In its March 27, 2025, Decision and Order in the Phase 2 Uniform Transmission Rate (UTR) proceeding, the Ontario Energy Board (OEB) ordered that a Working Group be convened to further examine the issue of double-peak billing.[1] The OEB tasked OEB staff with facilitating this Working Group as it gathered information, analyzed the issue, and provided recommendations. The OEB also determined that case-by-case exemptions to gross load billing may be appropriate through transmitter licence amendments.[2] In this regard, the OEB tasked the Working Group to examine and report back on gross load billing exemptions and the criteria for those exemptions.

In Procedural Order No. 3, the OEB clarified that this phase of the generic proceeding would only deal with UTRs and the impacts on transmission-connected customers.[3]

The following parties from the OEB's letter issued April 29, 2025, participated in the Working Group (collectively, the members):

- Association of Major Power Consumers of Ontario (AMPCO)
- Distributed Resource Coalition (DRC)
- Energy Probe Research Foundation
- Energy Storage Canada (ESC)
- Entegrus Powerlines Inc.
- Environmental Defence Canada Inc.
- Glencore Canada Corporation (GCC)
- Hydro One Networks Inc. (HONI)
- Niagara-on-the-Lake Hydro Inc.
- Vulnerable Energy Consumers Coalition (VECC)

The IESO and ESC participated as observers. OEB staff facilitated the Working Group by organizing meetings to discuss topics; supporting the discussions; and preparing this report. Members of the Working Group reviewed and contributed to the writing of this report. The Working Group held six meetings between May 8 and June 17, 2025, to

[1] Decision and Order, EB-2022-0325, p. 14
[2] Decision and Order, EB-2022-0325, pp. 35-36
[3] Procedural Order No. 3, July 5 ,2024, p. 3

discuss various elements of this report, with members attending on the basis of their interest and contribution of the material.

## RECOMMENDATIONS TO THE OEB

The Working Group makes the following recommendations to the OEB regarding double-peak billing:

- That the OEB establish a mechanism for transmitters to issue refunds for double-peak billing transmission charges to their customers. Most members recommend refunds whenever there is sufficient data to calculate the incremental charges and no estimation is required. These members expect this to typically, but not always, be situations relating to planned outages. The Transmitter that is a member recommends that refunds only be issued in relation to planned outages. This is because temporary metering is generally available for establishing baseline data and that should be required for there to be a refund. A high-level summary of the proposed methodology is included in the section titled "General Process to Determine Double-Peak Billing Refunds." The information used in that process would also be included in proceedings where the OEB reviews the refunded amounts.

- That the mechanism include a deferral account for transmitters to later recover the refund amounts; and that this deferral account include the incremental material administrative costs to transmitters to issue these refunds to their customers. These incremental administrative costs would be recorded in a sub-account.

- That the OEB establish an eligibility threshold that customers must meet to seek a refund. Most members recommend a threshold test based on a percentage of revenue requirement, while some other members recommend a dollar per customer threshold. For Industrial Transmission Customers, the Working Group considered two options but did not have time to fully discuss the question.

- That the OEB grant the Working Group at least three months to propose a process to determine refunds when estimations are required. This is expected to typically relate to unplanned transmission outages. This additional time could also be used to determine refunds for embedded distributors where metering data is not available. One member raised concerns regarding the lack of experience with double-peaking under the many possible unplanned outage scenarios that could occur. These include concerns with the volume of refund requests that would be generated. Some other members take a very strong position that unplanned outages must be included in the mechanism to address double-peak billing. These members do not support a solution that does not provide an avenue to address unplanned outages.

- The Working Group would use the additional time to:

    1. Identify historical events and different unplanned outage scenarios to support the analysis.

    2. Confirm a methodology or methodologies to estimate reference single-peak baselines when data and information is limited.

    3. Perform modelling to validate the proposed methodologies.

    4. Allow time to test alternatives.

- That the OEB confirm that the double-peak billing issue will be addressed for embedded distributors by allowing this Working Group to develop a proposal. The Working Group agrees that double-peak billing between transmission and embedded distribution delivery points is an important consideration. This is because the majority of distributors have at least some connection to a host distributor to serve their load.

The Working Group is providing the following recommendations related to gross load billing exemptions:

- **Criteria for Exemptions:** The criteria for the purpose of determining whether a generic or case-by-case gross load billing exemption is appropriate should include one requirement –that 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 – and the consideration of the following in a balanced manner:

    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.

- **Regional Planning scenario**: An exemption that would 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 forego 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 their capacity allocation. Since this is a relatively complicated scenario, implement it on a pilot project basis, at this time, to allow for a thorough assessment of the potential implementation issues. Some members support a pilot project but only if the embedded generation is part of the solution that meets the regional need (i.e., transmission constrained area not sufficient).

- **Transmission Capacity Constraints scenario:** Include 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. 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. This exemption should be conditional on the transmitter – and the IESO (where applicable) – completing the necessary technical assessments as a prerequisite. The Working Group has recommended wording for the UTR Rate Order.

- **Industrial Conservation Initiative (ICI) scenario:** Do not pursue an exemption, at this time, involving customers that only use their embedded generation to chase the "high 5" peaks, under the ICI program, due to the lack of Working Group agreement and implementation concerns regarding metering that could not be addressed.

- **Renewable Generation Support scenario:** Do not proceed with an exemption, at this time, that would apply to all renewable generation due to a lack of Working Group agreement on the purposes and merits of an exemption in relation to this scenario.

- **New Peak Shaving Embedded Generation scenario:** Some Working Group members support an exemption for all new embedded generation that is installed to offset some or all of the peak demand arising from a customer's new facility or an expansion to an existing facility. For clarity, this proposed exemption would not be limited to transmission constrained areas.

The Working Group is also providing the following recommendations that are not directly related to gross load billing exemptions:

- **GCC scenario:** Provide GCC with an exemption from the retail transmission service rate (RTSR) network charge to avoid GCC paying duplicative transmission network charges (to HONI Distribution and transmission charges to the IESO). HONI is of the view that GCC should be treated as part of the broader double peak billing issue – rather than through an exemption. If an exemption is approved, there is full agreement that HONI Distribution would need to be held harmless via the approved solution to address the broader double peak billing issue (i.e., through a refund and deferral account) and apply it to GCC's situation, for consistency. For the interim period, three options have been provided for OEB consideration.

- **Potential Comprehensive Assessment**: Some Working Group members support the OEB conducting a comprehensive examination into gross load billing because those members believe that the generic exemptions that the Working Group has been able to arrive at through a consensus approach do not fully address the concern stated in the OEB's UTR Phase 2 Decision that "applying gross load billing in a strict manner under the UTR schedule may lead to unintended consequences or inefficiencies".

In relation to the recommendations set out above, unless a different view has been identified (e.g., HONI vis-à-vis approach to address GCC), the Working Group reached a consensus. For those that refer to "some" Working Group members, the recommendation has been provided by a minority of members; that said, in both cases, there was limited time for the Working Group to discuss and consider them.

## MATTERS RELATED TO DOUBLE-PEAK BILLING

For reference, the Decision and Order stated the following with regard to double-peak billing:

> *Given the disparate views on this matter, the OEB finds it appropriate to convene a Working Group to examine the issue further. The Working Group, to be facilitated by OEB staff, should include representatives from transmitters, transmission-connected customers, and LDCs, ensuring a balanced representation of interests. The Working Group may not achieve consensus on all points but is tasked with gathering information, analyzing the issue, and providing* recommendations *on the following (non-exhaustive) list of questions by June 27th, 2025:*
>
> 1. *Whether double-peak billing is an issue with costs material enough to affected parties that a mechanism needs to be established to effectively deal with the problem.*
> 2. *If the answer to #1 above is yes, what mechanism(s) should be established to effectively deal with the problem? Such a mechanism could include, but may not be limited to, establishing a deferral account, changing charge determinants if feasible, or aggregating delivery points.*
> 3. *If double-peak billing is a problem, does the problem apply to both planned and unplanned outages?*
>
> *The Working Group may also identify and make recommendations regarding other considerations relating to double-peak billing for UTRs. The OEB will review the Working Group's findings and determine the appropriate next steps.*

This report summarizes the Working Group's analysis of the matters outlined above. The members generally view double-peak billing as a material issue that warrants a mechanism to address it. The members generally agree that a deferral account is the best mechanism to address the issue. The members also agree that there is an onus on transmission customers to support transmitters with data and analysis to determine the impact of double-peak billing events and the level of refund to those transmission customers.

### All Working Group Members Agree Double-Peak Billing is, in some way, a Material Issue

There is a consensus that double-peak billing for transmission service results 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 agrees that the monetary impact of double-peak billing, the pervasive nature of those charges, and the operational impacts of customer actions to avoid the additional transmission charges, make this a material issue.

While load transfers are recognized as a normal aspect of operations, most members view double-peak billing of transmission charges due to outages for transmission system assets to be unfair. This is based on the view that transmission customers are being charged twice for the same service. Most members view any additional provincial and / or retail transmission service charges levied on embedded distributors for outages outside of their control to be equally unfair.

Furthermore, these members assert that the additional charges are material when compared to the OEB's established materiality thresholds for the affected distributors. Some members of the Working Group represent distributors with materiality thresholds ranging from $50,000 to $250,000. The LDC Transmission Group's[4] evidence estimated double-peak billing events with costs ranging from $11,000 to $642,000.

The Working Group has consensus that the issue is material for all three UTR charges. Additionally, there is a consensus this situation is pervasive: the load transfers that result in double-peak billing are expected to regularly occur, and this situation could affect any transmission customer with more than one delivery point. As this issue is pervasive, there is consensus that this issue equally applies to non-regulated transmission customers. As a result, the Working Group recommends the same solution be applied in principle to transmission-connected commercial and industrial customers.

All members of the Working Group agree that, currently, transmission customers are likely to make efforts to avoid double-peak billing charges, affecting outage planning and execution. There is consensus that these customer actions have a material

[4] Through the proceeding, the following intervenors coordinated filing evidence as "The LDC Transmission Group": Niagara-on-the-Lake Hydro Inc., Canadian Niagara Power Inc., Enwin Utilities Ltd., Entegrus Powerlines Inc., Halton Hills Hydro Inc. Their filed evidence also included input from: Milton Hydro Distribution Inc., Kingston Hydro Corporation, Wellington North Power Inc., Hearst Power Distribution Company Ltd., Renfrew Hydro Inc.

negative impact on the operations of both transmitters and distributors. These efforts to avoid double-peak billing charges have negative impacts on safety and reliability, and also increase the costs to execute planned outages. As a result, the Working Group members look to the OEB for a decision on this issue.

Planned and Unplanned Transmission System Outages and the Availability of Data

There is a consensus among the members that double-peak billing charges would occur during both planned and unplanned transmission system outages. As a result, most members view unplanned outages as equally deserving of refunds: the double-peak billing nature is the same, regardless of whether the outage is planned or unplanned. The discussions on planned and unplanned outages relate to the challenges of establishing an objective, replicable, and auditable process, for estimated and metered double-peak billing scenarios.

There is consensus among the members that the process for evaluating double-peak billing events for refunds is different depending on whether the loads that result from the transfer have been directly measured or not. When planned outages are executed, it is expected that there will be temporary metering installed and switching details will be available. Transmitters are of the view that such metering and switching details should be a prerequisite for assessing and issuing refunds. This would provide an objective method to establish a “single-peak baseline” for each of the delivery points that are part of the load transfer or transfers subject to double-peak billing.

The members do not expect the same measurements or data to be consistently available during unplanned transmission system outages. This includes differences relating to available data to measure demand at all the delivery points and lack of logging to document equipment configurations. This is due to an operational focus on restoration during unplanned outage events. The configuration of equipment during planned outages is documented and known in advance of the transmission outage. This is not expected to be the case in unplanned outages. Additionally, restoration activities may result in a greater number of load transfers involving more equipment and delivery points than would be expected for a planned outage. These factors mean that determining the incremental double-peak billing charges that result from unplanned outages is typically more complex and is based on less available data.

The Working Group has not yet been able to resolve these differences and to develop an objective process to calculate the refund amounts where data gaps exist. This could lead to disputes between transmitters and their customers, making it more difficult to justify the refunded amount and making audits more challenging. To those members who pay the transmission charges, there should be a remedy. Transmitters, who would be responsible for issuing refunds, have concerns about the ability to determine appropriate refund amounts.

There is also consensus that the onus is on the transmission customer to fill any data gaps required to quantify the impact of the transmission outage. There are many plausible situations where the transmitter would not have the requisite measurement data available to establish a “single-peak baseline” and then to quantify the impact of the double-peak on the charge determinants. Additionally, while experience suggests that quantifying the impact on transmission charges resulting from planned outages should be possible, there is very little to no experience with quantifying the impacts due to unplanned outages.

Within the Working Group, there is disagreement regarding the estimation process to determine refunds when there is insufficient measured data. Transmitters raise concerns regarding how to establish a baseline for the refund while Distributors think that the challenges are not as difficult as Transmitters present. In discussing how to calculate refunds, 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.

The Transmitter member of the Working Group strongly believes that any approved estimation process that supports double-peak billing refunds must follow the above principles. The Transmitter member has the following concerns regarding an estimation process for double-peak billing refunds and disagrees with the basis provided by the Distributor members:

- The IESO is responsible for collecting and processing transmission meter readings, and issuing bills to all transmission connected customers.
- Transmitters do not have tools to estimate readings.
- Distributor meter reading collection and processing (including validation, estimating and editing) processes differ from those of the IESO.
- The refund calculation requires determining a single-peak baseline, which requires establishing how much load was transferred between delivery points and cannot be determined using wholesale meter readings.

In the absence of customer-installed electronic recording ammeters or other smart devices, estimation is required to determine the refund amount. The Working Group considered that refunds based on any other methodology could perhaps be administered by the customer's Metering Service Providers and the IESO.

From the perspective of distributors, a reasonable estimation process to support refunds, when measured data is unavailable, can be established on the following basis:

- The customer’s meter reading data is readily available for use in the refund calculation.
- Given that double-peak billing situations are irregular and vary in how they occur, Excel should suffice, as it has been used by some transmission customers for estimating and calculating double-peak billing impacts in the past.
- It is the availability of data, rather than the collection processes, that matters.
- Transmission charges are a pass-through cost for distributors. For the distributors double-peak billing is all about fair charges for their customers.
- Estimation is regularly used by the IESO for transmission billing and distributors for customer billing.

In general, the Working Group members agree that the concerns relate to estimating the baseline to calculate a refund. Some members think this challenge applies to nearly all unplanned transmission outages while others think there will be unplanned outages without this issue. For some members, the imprecision associated with estimation would be immaterial when compared to the double-peak billing impacts. The members generally agree that one of the concerns of applying a remedy to unplanned outages relates to the availability of data to support the refund process.

For the above reasons, coupled with the diversity of transmission customer configurations, the Working Group member representing transmitters continued to advocate for compensating transmitters for the administrative burden of the refund process. Expected incremental costs include incremental staffing to validate and process the refunds, and system and process changes required to deal with the volume of refunds, among other costs. Furthermore, since it is the IESO, and not transmitters, that meters and bills transmission connected customers, transmitters do not have software required to perform bill calculations. All of the above steps will be manual administrative work. No member questioned these concerns or disagreed with transmitters seeking relief for the incremental costs of administering refunds if found to be material.

The Nature of the Work that Leads to an Outage

The Working Group's discussions went beyond the question of planned and unplanned outages, as some members consider that any material outage warrants a refund, regardless of the nature of the equipment that requires the maintenance. Some members take the position that transmitters should issue refunds when the outage relates to any transmission equipment, whether customer- or transmitter-owned. This is based on the view that resolution should be the same, irrespective of the ownership of the transmission equipment.

As an example, some transmission customers own their transformation connection assets. Members holding the above view think that refunds should be issued even when the outage relates to customer-owned transmission equipment. This is because these members view the double-peak billing charges themselves to be at the core of the issue. They consider any double-peak billing charge unfair, regardless of the cause of the outage.

With respect to distribution equipment, there are situations where a load transfer is initiated in response to situations on the distribution system. There could be an unplanned outage on a distribution feeder, which is the customer's equipment. In the response, there could be a load transfer between delivery points. This situation could also result in breaker action within the transformer station, potentially appearing to be an unplanned outage on transmission equipment.

A Working Group member emphasized another important clarification. There are instances where an embedded distributor responds to an outage on upstream equipment, which is not under their control, resulting in double-peak billing charges. Some members think that these situations warrant a refund, as the root cause could be either with the host distributor or the transmitter. This was identified as an impactful condition in Hydro One's Background Report as example 6 and the Entegrus July 7, 2024 letter to the OEB.

In considering the various perspectives of different members and the above nuances, the Working Group reached a consensus that refunds should not apply to situations when the load transfer is performed in response to:

- The customer's own actions, planned or unplanned, on their distribution system
- Faults in the customer's distribution system that cascade up to cause an outage on the transmission system

A Threshold Test, Limitation Period, and Dispute Resolution

There is a consensus that establishing eligibility criteria would mitigate some implementation concerns and the administrative burden of processing refunds. However, the challenge of data availability to establish a baseline would continue.

For transmission customers who are distributors, most members favour a threshold test for each double-peak billing event based on a distributor's revenue requirement. This threshold test would be aligned with OEB materiality thresholds for cost-of-service applications. This type of threshold test would be consistent with OEB materiality thresholds that are standard to OEB proceedings.

Some members argued that the $50,000 revenue requirement threshold would be too restrictive for very small utilities. Two options were considered. The first was a lower threshold, such as $20,000. The other option was a dollar per customer basis, such as $3 per customer. Some members prefer a dollar per customer threshold for all distributors seeking a double-peak billing refund.

Members noted that in the case of non-regulated transmission customers, a different threshold test would need to be applied, if the OEB determined one is required. This is because a revenue requirement test does not apply to these customers. The Working Group considered two options: no threshold or a percentage of annual transmission delivery costs. The Working Group did not have time to discuss these two options to make a proposal to the OEB.

There is consensus that a limitation period would be appropriate. Considering that the financial impact to LDCs manifests in the Retail Settlement Variance Accounts (RSVAs), the Working Group agrees that transmission customers and transmitters would need to account for the refund in the same year that the event occurs. The members recommend that claims for refunds should be initiated within three months of the double-peak billing event.

The Working Group members acknowledge that transmitters would need to review supporting data, which raises a concern with the transmitter's ability to manage the workload associated with a likely increase in the number of requests for refunds once a formal process is established. In relation to this review, the members discussed options to resolve potential disputes between transmitters and their customers. The members acknowledge that transmitters and their customers may disagree on the amount of the refund or the nature of the outage for which transmission customers seek a refund.

Generally, the members agree they would prefer an "independent arbiter" for potential disputes. The members think that disputes could arise on the basis of the nature of the outage, the accuracy or quality of the data, the estimation process to determine a refund, or the level of the refund. The Working Group did not have time to fully discuss the following brainstormed options:

- An OEB process for applying for general eligibility to seek refunds from the transmitter
- An OEB proceeding prior to issuing a refund to resolve a dispute
- Both parties of the refund, the transmitter and the distributor, account for the refund in their own deferral accounts, for OEB review on disposition

**The Working Group Supports a Deferral Account Mechanism**

Currently, a double-peak billing event will result in higher amounts charged by the IESO and reflected in RSVAs 1584/1586 as a Regulatory Asset. The resultant debit will be cleared when the OEB processes the distributor's annual rate update or rebasing application, and the balance will be collected from the distribution customers in the subsequent year. The distributors represented in this proceeding seek to avoid this collection from their customers. The distributors do not want their customers to bear the cost of the double-peak billing event, for the reasons noted when the members considered the materiality question. To do this, distributors seek a refund to offset the increased transmission charges. With a refund for the portion of transmission charges attributable to the double-peak billing event, the transmission charge expense will be reduced. This will allow distributors to reduce the balance of Account 1584 and Account 1586 brought for disposition, reducing the subsequent collection from their customers in the following year.

Two questions arise. The first relates to the accounting of the refund for the distributor and their RSVAs 1584/1586. This includes considering whether (Option 1) the distributor should create sub-accounts for both Account 1584 and Account 1586 to record the refunds received from the transmitter; or (Option 2) the distributor should establish a separate new Group 2 account to record the amounts resulting from Double Peak Billing and its refunds. The Working Group proposes sub-accounts for Account 1584 and Account 1586 (Option 1).

The second question is whether a prudence review is required prior to the transmission customer receiving a refund and if yes, which party should bring forward that review. The Working Group proposes that a prudence review should not be required if two conditions are met. The first would be that the transmitter and the customer use the OEB's approved methodology to calculate the refund. The second would be that the transmitter and the customer agree on the refunded amount. The Working Group proposes that if these two conditions are met, the refunds would be pass-through costs that do not require OEB prudence review.

The following are the details for the accounting framework:

**1. Distributor side:**
Option 1: The distributor creates sub-accounts for both Account 1584 and Account 1586 to record refunds received from the transmitter:

- When a double-peak billing event occurs, the elevated transmission charges would result in an increase (debit) in the balance of Account 1584 and Account 1586.

- When the transmitter issues a refund to the distributor, the distributor will record the refunded (credit) amount to the sub-account of Account 1584 and Account 1586.

- Account 1584/1586 sub-accounts would record any unrealized refunds that, due to timing (billing lag), have been agreed upon with the transmitter and not yet received. This amount will then be reflected in the principal adjustment column of the DVA Continuity Schedule to ensure the balances of Accounts 1584 and 1586 brought forward for disposition has excluded the unrealized/expected refunds from the transmitters due to double-peak billing events.

Option 2 (as an alternative to the preferred Option 1, for the OEB's information and consideration): The distributor creates a Group 2 DVA to record the double-peak billing amounts and its related refund:

- When a double-peak billing event occurs, the associated transmission charges that reflect the elevated transmission load would be treated as an incremental cost and result in an increase (debit) in the balance of the DVA.

- Based on the agreement between the distributor and the transmitter, once the distributor receives the refund from the transmitter, the balance of the DVA will decrease (credit) the same amount to reflect the amount received resulted from the double-peak billing.

- The distributor would record a principal adjustment to reflect any unrealized/ expected refunds resulted from double-peak billing at the year-end due to timing (billing lag).

- This Group 2 DVA would include the total amounts of double-peak billing, and the refunds received/expected to be received from the transmitter for the period from January 1 to December 31 for that year. Therefore, the ending balance of this Group 2 DVA should be zero at the end of the year reflecting the amount resulted from double-peak billing equals to the refunds received/expected to be received from the transmitter.

- The total refunds/expected refunds recorded for the entire calendar year should agree to the amount recorded in the sub-account of the Group 2 DVA created from the transmitter side for each specific distributor.

- This Group 2 DVA is only for tracking purpose and will not be allowed for disposition.

- Carrying charges are not applied for this Group 2 DVA

**2. Transmitter side:**

- The transmitter who issued the refund would have also recorded the refund in its own newly created Group 2 deferral account.

- Where each distributor would record the impact of the refunds in its own Account 1584 and Account 1586, the balance in the transmitter's deferral account would collect the sum of all the refunds it issued to the transmission connected customers the applicable distributors.

- The balances in this account could be brought forward either at the time of annual rate updates or with a cost-of-service re-base application. The OEB could consider ordering the annual disposition of these balances. The OEB could further consider whether the "Transmitter's side" of the refunds should be reviewed prior to final disposition of the Distributor's Account 1584 and Account 1586. If the OEB determines this to be the approach, the Distributors could still seek disposition of the balances that are reduced by the refunds with the Distributor's annual rate updates on an interim basis. These dispositions would be interim until the final disposition of the Transmitter's account, should the OEB determine this to be the case.

- The transmitter must provide the following information when it requests to disposition this account:

    - Establish a sub-account for each of the three UTR charges, and track the refund issued to each LDC, for each year, in the sub-accounts
    - The amount of the refund that relates to each of the three UTRs
    - The transmission customer that received the refund

  - The month and year to which the refund relates

- The transmitter's incremental administrative costs should also be recorded in a separate sub-account to distinguish these costs from the issued refunds. The Working Group recommends that the administrative costs for transmitters to issue refunds be included in the transmitter's deferral account. The Working Group proposes that these administrative costs be recorded in a separate sub-account other than the sub-accounts where the double-peak billing amounts/refunds are recorded of the transmitter held deferral account

The Working Group believes that when the Transmitter and its customer agree on the refund amount and its basis, the refunds are pass-through amounts that would not require a prudence review. The Working Group proposes that if the distributor and transmitter use an OEB approved methodology to determine the refund amount, and the two parties agree to the refund amount, the refund would be a pass-through cost as with all other amounts that relate to the RSVAs. In this proposal, the distributor's sub-accounts only record agreed upon refunds. This means that if there is disagreement, there should be no amount recorded. This is since transmitters would not issue a refund to distributors when there is a dispute. In this case, no refund will be recorded in either the distributor's or transmitter's accounts. Most members suggest that this proposal would allow all reviews for disposition to be mechanistic in nature. Some members note that any party in a proceeding to disposition amounts relating to the refunds could challenge the prudence of a particular refund, even though it is a pass-through cost.

While the Working Group's above proposal assumes all refunds are undisputed, some members propose that if there is disagreement between the distributor and the transmitter on the refund amount, then the distributor should be allowed to account for their assessment of the refund amount. This assessment would be done regardless of whether any refund is issued by the transmitter. This would reduce the balances in the distributor's RSVAs. Then, upon seeking disposition of these accounts, the distributor's submission would include their view of the refund amounts with supporting evidence for the OEB to review. In the view of the distributors, the associated transmitter would have the opportunity to intervene. In this way, the OEB would resolve the dispute by reviewing the evidence supporting the refund. Another member supports that the distributor should have the choice to adjust the RSVA balances prior to the resolution of the dispute, depending on the circumstances. That member views the OEB's review of the dispute to be a transparent process to resolve the dispute.

**Additional Considerations**

The Working Group also considered other aspects of double-peak billing. Specifically, the members discussed how transmission service charges are affected by load transfers between two transmission-connected customers (e.g. example 5 from the HONI Background Report) and between transmission and embedded distribution delivery points (e.g. examples 6 and 7 from the HONI Background Report). If an embedded distributor's load is transferred between two such delivery points, the change in load at the distribution delivery point would affect the RTSRs charged to the embedded distributor and would also affect the UTR transmission charges for the host distributor. This results in double-peak billing events that affect multiple parties.

There is consensus that these scenarios should be important considerations for the OEB at this time. This is because only a minority of distributors have only transmission connected delivery points. The majority of Ontario's distributors have at least some connection to a host distributor to serve their own load. The Working Group agrees that a mechanism to address double-peak billing should consider this majority of distributors.

Therefore, the Working Group recommends that the deferral account mechanism be extended to host and embedded distributors. This is because the members think that no distributor should pay additional transmission service charges, whether by UTRs or RTSRs, as a result of events that are outside its own control.

The Working Group proposes that the ideal mechanism would be that the embedded distributor is also approved to establish a deferral account for double-peak billing refunds. In this way, the host distributor can seek and then pass on a refund in response to a load transfer to serve an embedded customer. The Working Group requests that it be given at least three months to develop a proposal to address this.

**General Process to Determine Double-Peak Billing Refunds**

This section contains the Working Group's proposed process for determining double-peak billing transmission charge refunds. The below figure shows the Working Group's intended final proposal to the OEB that resolves double-peak billing charges in all transmission outage scenarios.

Most members propose that the OEB approve this for transmission outages based on the availability of data. One member recommends the OEB approve the process only for planned outages at this time. Data is expected to typically be complete and available for planned outages. When the data is complete, the incremental double-peak charges can be calculated. When the data is incomplete, estimations are required to determine the incremental double-peak charges. The incomplete data scenario is the situation the Working Group requests to have additional time, so that it may develop a proposal for the OEB's approval.

The Working Group has identified that the following details are required to determine the refund amounts without estimation:

1. Plan, install and obtain temporary meter readings
2. Obtain switching details
3. Using above (1) and (2), determine the “single-peak baseline”
4. Recalculate applicable UTR transmission charges per UTR schedule requirements
5. Calculate refund by subtracting (4) above from the IESO billed transmission charges

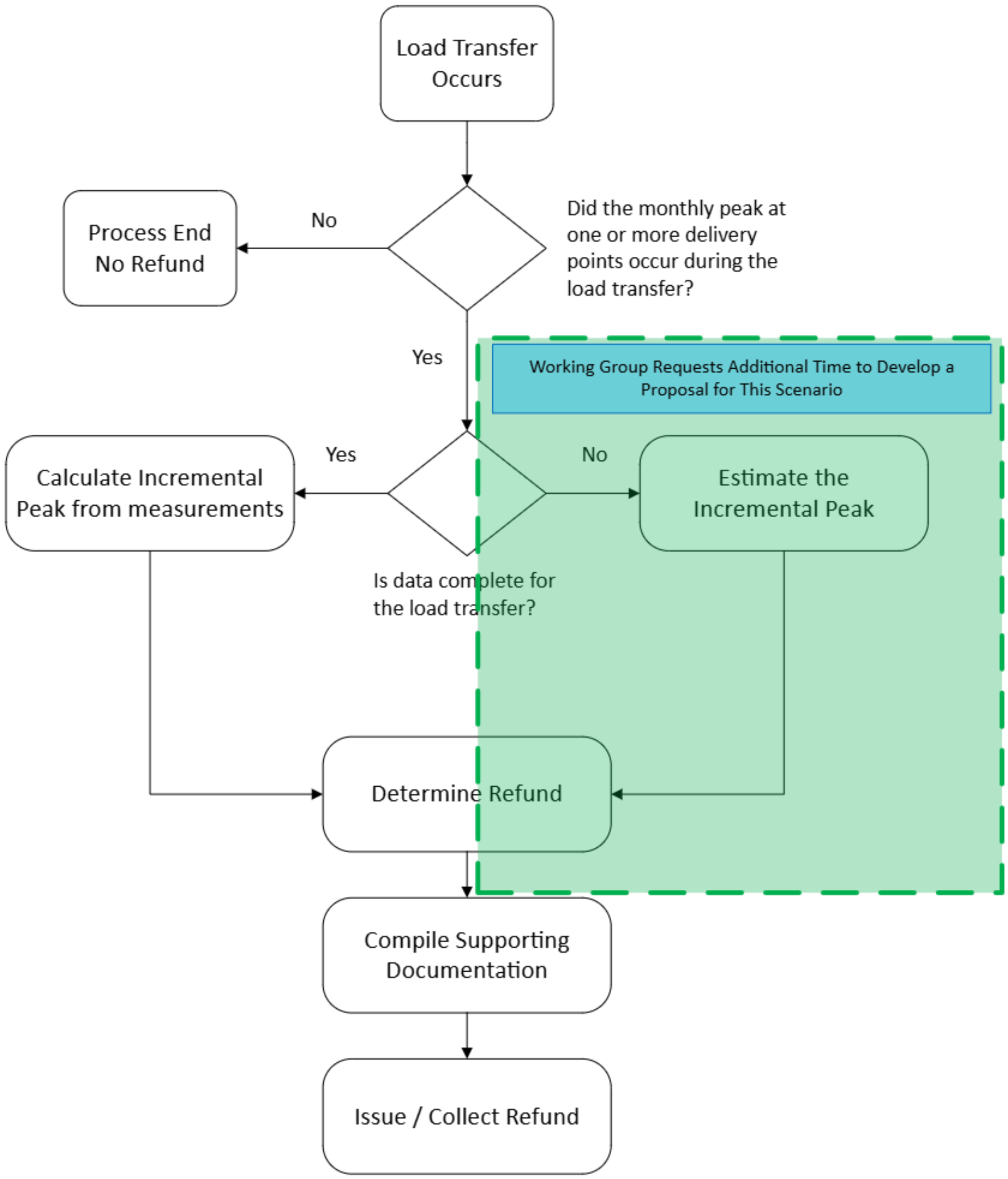


*Figure 1: Proposed Process to Determine Refund for Double-Peak Billing Charges - Highlighting Additional Work the Members Request to Undertake*

## MATTERS RELATED TO EXEMPTIONS

The UTR Phase 2 Decision & Order (UTR Phase 2 Decision)[5] stated that 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. There was also discussion of case-by-case exemptions under transmitter licences where transmitters may seek exemptions from specific provisions in the OEB's regulatory instruments and indicated such applications must provide evidence supporting the need for an exemption, and demonstrate alignment with system constraints and cost recovery principles.

The UTR Phase 2 Decision also stated that the Working Group was to examine and report back on gross load billing exemptions. In doing so, the OEB suggested that the Working Group should be tasked with the following:

- Develop clear criteria for gross load billing exemptions (e.g., transmission system constraints, renewable generation support).[6]
- 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."[7]

The Working Group was also tasked with the following:[8]

- Evaluate the GCC scenario 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 concluded in noting that it supports a balanced approach to gross load billing exemptions, addressing technical constraints, fairness, and policy objectives, and will find on this issue after considering the recommendations from the Working Group.

[5] Decision on Issues 4, 5, and 6, EB-2022-0325, p.33 - 36
[6] Decision on Issues 4, 5 and 6, p.36
[7] Ibid
[8] Ibid

**<u>Working Group Assessment and Recommendations</u>**

The Working Group notes that a conclusion was reached on the recommended criteria for exemptions following a full evaluation of all the scenarios. An initial set of criteria that guided the discussions of the scenarios was refined over time based on the Working Group deliberations during the meetings and the drafting of this report. The scenarios included those that were referenced in the UTR Phase 2 Decision Findings – Transmission System Constraints (e.g., HOSSM application), Regional Planning Considerations, Renewable Generation Support and GCC's scenario. The Working Group also assessed the scenario related to the Industrial Conservation Initiative (ICI) that was discussed in HONI's Background Report.

### Criteria for Exemptions

The Working Group is recommending the following criteria for the purpose of determining whether a request for a gross load billing exemption is appropriate:

- The one requirement is 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.

Consideration should also be given to the relevant factors set out below and 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).[9]
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.

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[9] In the OEB's Renewed Regulatory Framework for Electricity (RRFE) Report (p.43), the OEB explained a change in it cost responsibility principles in stating "a shift in emphasis away from the 'trigger' pays principle to the 'beneficiary' pays principle is appropriate".

7. Implementation costs should be reasonable.

In relation to the criterion related to the risk of stranded assets above, some Working Group members expressed the view that there should be "no" risk at all. The other view is absolutely "no" risk sets the bar too high and "no or minimal" risk should be sufficient, and it can be left to the decision maker at the OEB to determine if the level of risk is acceptable.

The Working Group's assessment of each of the scenarios is set out below.

**Scenarios**

**1. Regional Planning Considerations Scenario**

As noted above, the UTR Phase 2 Decision stated: "The Working Group may also consider addressing exemptions through the regional planning process, ensuring transmission system upgrades, embedded generation, and customer load growth are holistically evaluated."

There is general Working Group support for an exemption that would apply where all of 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 forego capacity that was originally built or planned to be built on the system to supply their load.

3. The customer and transmitter agree to the following:

    a) A solution that would ensure that the customer does not exceed their capacity allocation (and associated terms, conditions, and obligations).

    b) A defined time period for the exemption.

With respect to the first criterion, the "transmission constrained areas" would need to be determined and re-assessed, from time to time, through the regional planning process to ensure they are determined on the same basis across the province and through a process where all types of solutions are assessed, i.e., wires and non-wires solutions (NWS). That aligns with the UTR Phase 2 Decision that placed this scenario within the context of regional planning considerations and identified the need for a holistic evaluation.

There are differing views related to whether a fourth condition should apply -- whether this exemption should be open to *existing* DERs, or *only to new and expanded* DERs. One view reflects restricting the exemption to *new and expanded* DERs because existing transmission-connected DERs can be utilized to address transmission constraints by contracting with individual facilities through an NWS assessment and/or regional planning processes, whereas some believe that is impractical for customers building a business case for new or expanded DERs due to timing reasons. The other view is that an additional condition would not be appropriate as it would unfairly result in existing embedded generation that meets the other three conditions having to apply for a case-specific exemption, whereas new embedded generation would not be required to do so. It should therefore apply to *both existing and new*.

There are also differing views as to how closely the exemption needs to be aligned with the regional planning process. One view is that the embedded generation would need to be part of the solution in a regional plan developed to address transmission constraints because that approach would be most consistent with the intent of regional planning. Another view was that, due to various factors such as the timing of the regional planning process (i.e., five-year cycle), that condition was overly burdensome and the condition should be limited to the embedded generation being located in a transmission constrained area of the province as identified by the regional planning process.

The Working Group believes that this exemption would encourage non-wire investments to be located in areas of the province where they are most needed (i.e., transmission constrained). The Working Group notes that it could be viewed as analogous to the IESO's recent introduction of locational marginal pricing (LMP), under Market Renewal, which incents new generators to locate where transmission congestion costs are high (i.e., exemption would similarly send a price signal). In addition, the condition that the customer be required to forego capacity 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).

A potential issue discussed by the Working Group is that the foregone capacity may not be taken up by another customer in some cases. The Working Group acknowledges that the proposal is not perfect and that may happen. However, that would likely be rare as the location will have been identified as transmission constrained through the regional planning process and load growth is forecast throughout the province.[10]

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[10] https://www.ontario.ca/page/ontarios-affordable-energy-future-pressing-case-more-power .

Members of the Working Group also raised a concern related to the customer using more capacity than the reduced contracted capacity (after committing to forego capacity) due to the potential impact on reliability. However, the Working Group has not addressed that potential issue in this report because that would not be an issue that relates to only this proposal. That would be part of a broader planning issue that would need to be addressed through the regional planning process, as any of the transmission customers across Ontario could be using more than the contracted capacity that they paid for, as reflected in the Connection Agreement with the transmitter. The Working Group has therefore assumed that transmission customers generally use the amount of capacity reflected in the contract that they sign with the transmitter, including those that forego capacity under this potential exemption.

Some Working Group members believe that criterion 3 may be unfair because it would limit some customers to their capacity allocation amount but not apply this same limit to customers without distributed energy resources (DERs).

In terms of implementation, the capacity that the customer foregoes would need to be formally reflected by the transmitter through an amendment to the customer's Connection Agreement – Attachment J2 (of Schedule J) of the Transmission System Code (TSC) – which reflects a "Customer's Assigned Capacity". Furthermore, the Connection Agreement shall specify how the customer's load supplied by the system will be limited to the customer's assigned capacity. This would enable the transmitter to reassign the foregone capacity to another load customer.

To be eligible for such an exemption, a customer seeking to forego capacity would need to make this request to the transmitter. The transmitter would need to make this option available to customers and an agreement would need to be reached with the customer in relation to this option prior to seeking an exemption from the OEB.

The Working Group notes that each customer that has received an exemption and foregoes capacity would ideally have it approved before the Needs Assessment stage, so it can be reflected in the Needs Assessment, which is the first stage in the regional planning process. The reason for that is the change (reduction) in the customer's capacity assignment should be reflected in the amount of available capacity on the transmission system. The Working Group also notes that the transmitter, who would be aware of all such exemptions, also leads the Needs Assessment stage of the regional planning process, in consultation with the other members of the regional Technical Working Group (i.e., IESO and applicable LDCs).

The Working Group notes that there is general support for this exemption. However, it would need to be implemented in a manner that does not compromise system reliability.

To that end, the Working Group also notes that this is a relatively complicated scenario from an implementation perspective. As such, the Working Group recommends that this exemption be implemented on a pilot project basis, at this time, 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 would also allow for refinement, based on lessons learned, in advance of broader deployment and inform the extent of uptake by customers. The pilot project would be limited in scope (i.e., a handful of customers, not open-ended) since the purpose is to assess implementation issues. The specific number of customers would depend on whether the circumstances of new customer requests to be involved are different from those already being tested as part of the pilot. There were differing views on the basis that the pilot project should be implemented – most Working Group members supported embedded generation located in any area that is transmission constrained, while some were of the view that it should be limited to where the embedded generation must address a specific transmission constraint. The pilot would therefore be implemented based on the three conditions discussed at the beginning of this section.

### 2. Transmission Capacity Constraints Scenario

The Working Group notes that this scenario was identified in the HONI Background Report.[11] It would apply where the customer's capacity needs exceed the available capacity on the transmitter's transmission system. Under this scenario, the customer has agreed to install embedded generation to meet its supply needs and cover the shortfall that cannot be provided from the system. 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.[12]

The Working Group also notes the positive attributes associated with this exemption – following an assessment by the transmitter and the IESO (where applicable) on the maximum amount of capacity that can be provided to the customer – are it would be relatively straightforward to implement. Once the necessary technical assessments are completed, no transmitter judgment should be required since a customer (e.g., industrial consumer) should only be charged for the capacity that a transmitter can technically provide to the customer. It would also provide flexibility to adjust the implementation of gross load billing in response to a transmission system constraint and would demonstrate alignment with the OEB's cost recovery principles since the customer pays

[11] HONI UTR Phase 2 Background Report, Issues 5 and 6. p.13
[12] For clarity, this scenario does not involve regional planning considerations.

to the extent they benefit from the system. This exemption would also not result in any cost shifting among transmission customers.

The OEB issued a Decision (under Delegated Authority) approving this exemption through a Hydro One Sault Ste. Marie (HOSSM) licence amendment to bill Algoma Steel on only a portion (15%) of its capacity needs (30 MW of 140 MW), as 30 MW is the maximum capacity that can be supplied by HOSSM's transmission system and HOSSM indicated that "there is no feasible solution to upgrade HOSSM's transmission system to supply all of Algoma Steel's new load".[13]

The Working Group notes that an exemption under this scenario was broadly supported across the spectrum in earlier written submissions by VECC, HONI, DRC and OEB staff (and there was no opposition to it). The IESO also supported HOSSM's application discussed above.

Given it is relatively straightforward to implement, after the transmitter (and IESO, where applicable) has completed all the necessary assessments to determine the maximum capacity that can be provided to the customer, OEB staff asked the Working Group the following question – "*Should this exemption be reflected in the UTR Rate Order to avoid the administrative burden (transmitter & OEB staff) related to an application and the potential for delays (customer)? Or is there still a reason to require an application?"*

The Working Group supports including the exemption in the UTR Rate Order; however, some Working Group members expressed the view that the wording for the "Terms and Conditions" section of the UTR Rate Order should not be overly restrictive and must account for scenarios beyond the specific circumstances outlined in the HOSSM application (i.e., transmitter cannot expand the system to meet the customer's short-term forecast capacity needs). The Working Group discussed a scenario where the system can be expanded and the exemption should still apply – that is, the customer's new facility is expected to be in place in 18 months, and the transmitter indicates that they cannot expand the system within 18 months to meet the customer's load but plans to do so in five years. The exemption should therefore be allowed during the five-year period until the transmitter completes the expansion, since that remains aligned with the HOSSM Decision. The wording for the UTR Rate Order should further reflect that it does not necessarily need to involve a transmission expansion. For example, capacity could be reallocated by the transmitter from another transmission customer (e.g.,

[13] Decision & Order, EB-2024-0357, May 6, 2025

industrial shut down operations, foregone capacity under regional planning scenario, etc.) to meet more or all the connecting customers' needs.

As indicated above, the Working Group's support for including this exemption in the UTR Rate Order is conditional on the transmitter – and the IESO (where applicable) – completing the necessary technical assessments as a prerequisite. In other words, all the same technical assessments would need to be carried out that would be necessary for the purpose of completing a licence amendment application (e.g., an IESO SIA was completed before the HOSSM application discussed above was submitted). This approach therefore would only avoid the need (and associated burden) for the transmitter to prepare and submit an application for approval by the OEB.

In the event that the OEB decides to reflect this exemption in the UTR Rate Order, the Working Group's recommended wording is set out below for the OEB's consideration.

> *"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."*

Timing of implementation of the exemption would need to take into account the time required for the IESO to develop and deploy a settlement solution, which could present similar challenges to those experienced by the IESO when implementing the Algoma Steel settlement solution.

This exemption would only apply on a go forward basis.

### 3. Industrial Conservation Initiative (ICI) related Scenario

HONI's Background Report stated 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, under the ICI, because the embedded generation is run only at select times during anticipated Ontario peak demand hours.[14] HONI provided additional detail during the Working Group discussions in noting the exemption would be limited to customers who are assumed to use the embedded generation about 20 times per year to chase the “high 5” peaks under the ICI.[15]

The Working Group notes that, if it is only about 20 times per year for ICI purposes, an exemption is unlikely to pose a risk of bypass and the stranding of assets.[16] It was further noted by a Working Group member that it should also result in a relatively immaterial reduction in transmission revenues that such ICI customers pay.

HONI identified another aspect of this proposed exemption that triggered much Working Group discussion. That aspect related to the metering of the embedded generation, which is necessary for gross load billing and would also be used to confirm that the embedded generation is only operating about 20 times per year. HONI noted that metering should not be required to avoid imposing the related costs on ICI customers, which range from $5,000 to $50,000 (depending on the size of the customer and other factors).

A Working Group member identified that small ICI customers (e.g., 500 kW) with embedded generation would not benefit from such an exemption since they are already exempt from gross load billing based on the 1 MW and 2 MW thresholds that apply to conventional and renewable generation, respectively. HONI clarified it is an issue for medium-size ICI customers – typically between 4 MW to 12 MW – and it is not an issue for large ICI customers.

The Working Group asked HONI, in the absence of metering, if there was another way to ascertain how often the ICI customers are actually using the embedded generation. HONI noted that they could monitor each applicable customer’s demand from the grid to identify if it is consistently below their typical level (i.e., using the embedded generation more frequently than intended). HONI also noted that they could be required to enter into a contract and, if they don’t comply with limiting the use of embedded generation to chasing the “high 5” peaks, then require the customer to install the metering. It was further noted that the customers could also be required to sign an annual attestation that they will use the embedded generation for only ICI purposes. HONI acknowledged

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[14] HONI UTR Phase 2 Background Report, Issues 5 and 6. p.14
[15] The TSC does not include a specific definition of “embedded generation”. However, section 11.1 is dedicated to “embedded generation” and each provision in that section describes it as a “generation facility is connected on the customer side of the connection point”.
[16] One potential unique scenario was raised by a Working Group member to OEB staff.

that the alternatives to metering (e.g., monitoring the demand of ICI customers, managing contracts) would result in additional administrative costs.

The Working Group notes that a key issue was identified in relation to providing this exemption which relates to it being indicated by the OEB that this proceeding is focused on only the UTRs. The exemption would therefore only apply to transmission-connected ICI customers and that would result in different treatment of ICI customers depending on whether they connect to the transmission or the distribution system. None of the Working Group members, including HONI, supported treating ICI customers inconsistently on that basis. As such, if this exemption is adopted by the OEB, the Working Group believes it should apply to all ICI customers including those connecting to the distribution system.

The Working Group representative representing AMPCO indicated that the customer concerns identified by HONI related to gross load billing have not been raised as an issue among its transmission-connected members. HONI indicated that was consistent with them finding that the concerns about gross load billing are typically coming from ICI customers that are distribution-connected.

Other concerns associated with this proposed exemption that were discussed by the Working Group included the following:

- It would not be aligned with addressing transmission system constraints since ICI customers are scattered across the province, including areas where there is excess capacity on the transmission system.
- Those Class A customers already benefit from reduced GA charges due to the ICI program.
- ICI customers using embedded generation in this manner are not reducing their demand for capacity on the system which was built to supply them.

For clarity, the Working Group notes that this exemption from gross load billing would only apply to new customers.

Some Working Group members indicated opposition to this proposed exemption (VECC, EP, Entegrus) both in principle and from an implementation perspective, particularly the aspect that involves not requiring the metering of the embedded generation. The remaining Working Group members appear to be neutral.

Given the Working Group's concerns with respect to metering, HONI indicated that it would assess internally if there was a way to implement this exemption in a manner that would address those concerns. After taking this back, HONI did not find a way in which to implement the exemption in a manner that would address the Working Group concerns regarding metering. As a result, HONI does not believe that the OEB should pursue this exemption at this time. The Working Group agrees it should not be pursued at this time.

As discussed above, if such an exemption were to be pursued in the future, the aspect where there is Working Group consensus is that both transmission- and distribution-connected ICI consumers should be treated the same with respect to the billing of transmission charges. As such the exemption should apply to both the UTRs at the transmission level and the RTSRs at the distribution level.

### 4. Renewables Generation Support Scenario

The primary rationale for an exemption under this scenario was to serve as an incentive to support decarbonization objectives. Some Working Group members identified other potential rationales, such as the provincial government's objectives to secure clean energy and empower customers to participate in the energy system through DERs.

It was discussed that the OEB recently issued a report – Benefit-Cost Analysis Framework for Addressing Electricity System Needs[17] – which notes: "The intent of the BCA Framework is to encourage the development of solutions that are in the best interests of …Ontario's energy customers … It seeks consistency in how distributors choose between NWS and traditional poles-and-wires infrastructure solutions to meet an electricity system need. As stated in the [Framework for Energy Innovation] Report, it is not the role of the OEB to increase or accelerate NWS adoption, or to choose one technology solution over another."

Some Working Group members interpret the above wording in the BCA Framework and FEI reports as intending to express that wires and NWS solutions should be assessed consistently without tipping the scales between one or the other. Other Working Group members interpret the final sentence as intending to relate to assessing all technologies consistently including among NWS options.

The Working Group concluded that this renewable generation support scenario should not be pursued because there was no agreement on whether a generic exemption would be appropriate.[18]

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[17] BCA Framework for Addressing Electricity System Needs, May 12, 2024, p.5
[18] Under the definition in the TSC, "renewable generation" means a generation facility that generates electricity using a renewable energy source as defined in the Electricity Act".

## 5. GCC Scenario

As noted above, the UTR Phase 2 Decision ordered the Working Group to "evaluate [the GCC] scenario for an exemption, given its distinct nature and potential fairness concerns". The OEB further indicated that the Working Group should "speak to fairness and cost recovery implications for unique cases, such as the double-peak billing scenario experienced by GCC."

Based on evidence from this proceeding (and the UTR Phase 2 Decision), OEB staff, as the facilitator to the Working Group, presented to the Working Group the following attributes associated with GCC in relation to its facilities in Sudbury at a meeting and no material changes have been made.[19]

- 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.[20]
- GCC's load transfers are only permitted if HONI Distribution has the necessary capacity available when GCC needs it.

HONI noted that it is aware of one other industrial customer and some LDCs that it believes have similar circumstances to GCC. HONI provided one specific example to the Working Group – Hearst Power Distribution. The Working Group notes that only GCC's specific circumstances have been examined in this proceeding, and the Working Group does not know if those other HONI customers share every attribute discussed

[19] The attributes listed were presented at the Working Group meeting on May 15, 2025. No concerns were raised at that meeting by the Working Group. As such, no material changes have been made to the list of attributes in this report.
[20] For clarity, HONI notes that if specific investments were made on the distribution system for GCC such that it could be permanently connected, GCC would be considered a distribution customer which would mean that it would be subject to all associated distribution charges, on a monthly basis, including monthly fixed charges (which would apply even if no load is being drawn from the distribution system).

above that applies to GCC. As such, the Working Group has focused on GCC, as requested in the UTR Phase 2 Decision. That said, the Working Group notes, if the OEB approves an exemption for GCC, HONI could submit a licence amendment application(s) for each of the applicable entities with similar circumstances (i.e., other industrial customer and the LDCs) and leverage the OEB decision on GCC in doing so.

There is general Working Group agreement that an exemption from the RTSR network charge would be appropriate to avoid GCC paying HONI duplicative transmission network charges. However, the Working Group notes that implementation issues would need to be addressed. Most notably, the Working Group believes HONI Distribution would need to be held harmless, since GCC's temporarily transferred demand increases HONI Distribution's network charges.

With respect to the OEB direction that the Working Group evaluate GCC for an exemption, HONI indicated that its evaluation was that it would be most appropriate and fair that that GCC be treated as part of the double peak billing issue and a comprehensive solution for double peak billing issues for transmission-connected and distribution-connected customers should be pursued to address concerns raised by LDC and industrial customers (including GCC). In other words, that approach would be more appropriate than evaluating GCC in terms of whether an exemption should be provided.

GCC notes, as reflected in UTR Phase 2 Decision, the OEB felt an exemption should be considered in relation to GCC (separately from the broader double peak billing issue). As noted above, there is general Working Group support for an exemption to address the fairness concerns associated with GCC paying duplicative network charges. Further deferral of addressing those fairness concerns to an undefined future process (which may not occur prior to further GCC outage driven load transfers) would necessitate continued payment to HONI by GCC of duplicative network charges. GCC added that providing such an exemption need not preclude reviewing any solution currently adopted for GCC (and any similarly situated parties) at the time of a broader review of double peak billing issues, if appropriate.

If an exemption is determined to be appropriate, the Working Group's recommended approach, from an implementation perspective, is to ultimately adopt the solution that is approved to address the broader double peak billing issue and apply it to GCC, for consistency.

For the interim period, the Working Group discussed three possible options – including two that involve the IESO – to address GCC's exemption in advance of a decision on the broader double peak billing issue:

1. HONI indicated that Option 4, as set out in the Background Report, is a possible approach to address GCC's situation. Under this approach, HONI Distribution would calculate the network transmission charges associated with GCC's demand and would request HONI Transmission to refund to HONI Distribution the network charges associated with GCC's demand previously charged to HONI Distribution. As a result, HONI Distribution would not bill the RTSR network charge to GCC (currently HONI Distribution bills the RTSR network charge to GCC). HONI Transmission would hold the deferral account, thus holding HONI Distribution's customers harmless, and HONI Transmission would subsequently seek disposition of its deferral account as part of a future proceeding.

2. Another option identified by OEB staff to the Working Group would avoid the administrative burden associated with HONI Transmission providing refunds and the administration of a deferral account (including an OEB review for disposition purposes at each rebasing application). It would involve exempting HONI Distribution from paying (and charging GCC for) the portion of the network charge associated with GCC's demand, which would be provided by HONI Distribution to the IESO. The Working Group requested the IESO's feedback in relation to the implementation of this option which is similar in approach to what is currently done for Algoma Steel. The IESO indicated that they found the Algoma Steel exemption to be a challenge to implement, and the two situations are not the same, so Algoma Steel's solution would not be replicable for GCC. However, the IESO noted that given the relatively infrequent occurrence of GCC load transfers (i.e., once or twice a year), the IESO anticipates that a solution to implement it would be possible. [21]

3. Another option involving the IESO would be to follow the IESO's Notice of Disagreement (NOD) process. It is similar to Option 3 in HONI's Background Report (i.e., adjust the charge determinants). Under this approach, HONI Distribution would submit a NOD to the IESO with supporting documentation on the double peak event associated with the transfer of GCC's load to Larchwood TS, citing the OEB decision related to the exemption. The IESO would review the submitted documentation and 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 Working Group notes that GCC, IESO and HONI plan to discuss the potential for a *pilot project* to test this option, under the OEB's Sandbox framework, in the event GCC experiences an outage before a

[21] Since the IESO is not certain about the implementation details, at this time, the Working Group did not have an opportunity to discuss implementation details associated with this option.

decision is made on the broader double peak billing issue. The Working Group further notes that such a pilot project is not intended to suggest that this option is being recommended by the Working Group.

HONI identified an issue associated with the third option set out above – transmitters would not fully recover their currently OEB-approved revenue requirement due to the refund. While this is not a material issue for an exemption that is limited to GCC, it could become one if this exemption was extended to include a material number of other transmission customers in situations like that of GCC. Option 2 would also have a revenue requirement impact for transmitters since HONI Distribution would be exempt from paying the portion of the network charge associated with GCC's demand to the IESO.

### 6. New Peak Shaving Embedded Generation Scenario

Some Working Group members support an additional generic exemption for new embedded generation that is installed to offset some or all of the peak demand arising from a customer's new facility or an expansion to an existing facility. An example of this potential exemption is a 10 MW new load facility that installs 2 MW of embedded generation such that they only need to request 8 MW of capacity from the transmitter. Those Working Group members believe an exemption to gross load billing is important to consider in this situation for the following reasons:

1. *Fairness:* The customer is likely not causing any stranded asset(s) via their embedded generation as long as the exemption is designed appropriately, such that charging them on a gross load basis is unfair;

2. *Cost minimization and efficiency:* System costs can be reduced by treating customers who install peak shaving generation to serve new load fairly as this will encourage more of this behaviour; and

3. *Empowering energy consumers:* The exemption would further the Ontario Government's goal of making "it easier for customers to adopt and benefit from DERs" by ensuring that those customers are not paying for transmission system costs that they have not caused.[22]

The Working Group did not have time to discuss this potential exemption in its meetings. However, concerns were expressed by a number of Working Group members

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[22] Ontario, *Energy for Generations Ontario's Integrated Plan to Power the Strongest Economy in the G7*, June 2025, p. 89 (The second pillar of Ontario's DER Strategy is "Empowering Consumers: Ontario will make it easier for customers to adopt and benefit from DER – giving families, businesses, and institutions more tools to manage their energy use, reduce costs, and contribute to a smarter, more flexible grid.")

(in written communications), including the lack of linkage to regional planning (e.g., embedded generation may not be located in a transmission-constrained area). The Working Group members that support this potential generic exemption are only proposing that it be explored further if a more comprehensive assessment of gross load billing, as suggested in the next section, is not examined in phase 3.

## 7. Potential Comprehensive Assessment

Some Working Group members believe that, while this Report addresses the tasks set out by the OEB for the Working Group, the generic exemptions that the Working Group has been able to arrive at through a consensus approach do not fully address the concern stated by the OEB's UTR Phase 2 Decision that "applying gross load billing in a strict manner under the UTR schedule may lead to unintended consequences or inefficiencies." Those Working Group members therefore believe it is critical that the OEB conduct the "comprehensive examination into gross load billing" referenced in the UTR Phase 2 Decision as soon as possible.[23]

Those Working Group members note that, although case-by-case exemptions and generic exemptions may improve system efficiency and fairness for some customers, they also have drawbacks. Those include administrative and regulatory burden, that few customers will qualify if exemptions are narrowly defined, the piecemeal nature of exemptions, and the requirement that exemption requests originate from the transmitter. In contrast, a comprehensive assessment of gross load billing (including potential rate design reform) could result in a more comprehensive solution.

Ontario's new Integrated Energy Plan includes a "DER Strategy" and states that "Ontario's energy system must evolve to … [m]onetize DER fairly, ensuring customers receive compensation that reflects the value their resources contribute to the grid."[24] It also refers to "bold steps to ensure DER are effectively integrated into system planning and decision-making at every level."[25] Some Working Group members believe it is important to go beyond generic exemptions via a comprehensive review of gross load billing to meet the goals of Ontario's DER Strategy, in addition to addressing other goals and considerations.

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[23] UTR Phase 2 Decision, p. 2, 23, & 24

[24] Ontario, *Energy for Generations Ontario's Integrated Plan to Power the Strongest Economy in the G7*, June 2025, p. 87

[25] Ontario, *Energy for Generations Ontario's Integrated Plan to Power the Strongest Economy in the G7*, June 2025, p. 89

The Working Group did not have time in its meetings to discuss the pros and cons of conducting a comprehensive assessment of gross load billing or what such an assessment would address.