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BY EMAIL AND RESS

April 2, 2024

Ms. Nancy Marconi
Registrar
Ontario Energy Board
Suite 2700, 2300 Yonge Street
P.O. Box 2319
Toronto, ON M4P 1E4

Dear Ms. Marconi,

EB-2022-0325 – Phase 2 of the Generic Hearing on Uniform Transmission Rates – Related Issues – HONI Background Reports on Issues 4 and 5/6

Further to Procedural Order No. 1 issued December 8, 2023, Hydro One is writing to provide its Background Reports on Issue 4, as well as Issues 5 and 6.

Please note that for the convenience of parties to this proceeding, Hydro One separated the Background Report on Issue 4 from the Background Report on Issues 5 and 6. This will allow parties who are particularly interested in Issue 4, or Issue 5 and 6, to focus on the issues they are interested in.

An electronic copy of this filing has been submitted using the Board's Regulatory Electronic Submission System.

Sincerely,

Uri Akselrud

Uri Akselrud

ISSUE 4 – CHARGES CAUSED BY PLANNED TRANSMISSION OUTAGES

1.0 INTRODUCTION

In its October 27, 2023 Notice of Hearing, the Ontario Energy Board (OEB) describes Issue #4 as follows:

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

To further understand this issue, the following sections provide an overview of the relevant historical context, a more detailed description of the issue, and a summary of those who are impacted by it. Potential options for addressing this issue follow.

1.1 HISTORICAL CONTEXT

The requirement that transmission charges must be based on the monthly peak at each delivery point is set out in the Uniform Transmission Rate (UTR) Schedule, which is attached as Schedule B to the OEB's Decision and Rate Order on UTRs each year. More particularly, Note 1 of the UTR Schedule (applicable to Network, Line Connection and Transformation Connection service rates) states:

> 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.

Part C of the UTR Schedule under the Terms and Conditions defines Transmission Delivery Point as follows:

> 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.

The determination that transmission charges shall be based on the monthly peak at each delivery point originates from the OEB's Decision with Reasons in RP-1999-0044, dated May 26, 2000 (the "Original UTR Decision"). In that proceeding, the OEB considered an application from Ontario Hydro Networks Company Inc. ("Ontario Hydro Networks", which was renamed Hydro One Networks Inc. just prior to the decision being issued) for approval of year 2000 transmission cost allocation and rate design. This was the OEB's first decision on cost allocation and the setting of transmission rates on a uniform basis following the unbundling of rates under the former Ontario Hydro.

In the Original UTR Decision, the OEB accepted the proposed use of a monthly billing cycle in Section 3.4.5, and in Sections 3.4.6 to 3.4.9, the OEB considered the manner in which transmission charges would be determined. The OEB recognized that there were two possibilities for charging for transmission services:

a) on an aggregate per customer basis, whereby the transmission charges would be calculated on the customer's aggregate demand for all delivery points for a given time interval; or
b) on a per delivery point basis, whereby the customer's charges would be calculated separately for each delivery point.

The applicant proposed use of the delivery point basis. Toronto Hydro argued that Ontario Hydro Networks should be required to explore the impacts of allowing transmission customers served by multiple delivery points to aggregate their total load for billing purposes and to report on this at its next rate case. The Municipal Electric Association (MEA) supported the proposal to assess transmission service charges on a per delivery point basis but argued that in circumstances where a Local Distribution Company (LDC) is served from more than one delivery point and due to maintenance at one delivery point demand increases at another delivery point, there ought to be a provision not to charge for the resulting "maintenance peak". MEA argued that this can be accomplished through appropriate notification for pre-approval of shifts among delivery points.

The OEB determined that "the alternative of allowing customers to aggregate demand from delivery points for billing purposes would provide an unfair advantage to those customers with diversity of demand from geographically different delivery points at the expense of other customers". The OEB was also of the view that "(providing an) allowance for shifting as suggested by MEA (would be) cumbersome, inconsistent with the user-pay or fairness principle and impractical". The OEB therefore accepted the applicant's proposal for transmission charges to be calculated on a per delivery point basis, with no provision not to charge for maintenance peaks under planned outages. The OEB did not elaborate on the nature of the unfairness or inconsistency with the user-pay approach, and there have been no changes or reviews of this approach since established.

1.2 DETAILED DESCRIPTION OF THE ISSUE

A double peak billing event can occur in instances where a transmission customer is supplied by more than one connection point to the transmission system, each of which is referred to as a delivery point (DP). At a time of a planned transmission outage[1] (for example to facilitate system maintenance or system upgrades initiated by the transmitter or the transmission-connected customer), the customer's load may be transferred from an impacted DP to another one of the customer's DPs in order to avoid or minimize power interruption. When this occurs, the customer may be charged for the same load on both DPs in a given month as a result of transmission charges being based on the monthly

[1] Unplanned transmission outage can also result in double peak billing events as further discussed below.

peak at each DP. For example, if during a billing cycle the load is transferred from DP(A) to DP(B), this would result in a higher monthly peak at DP(B) due to the combined load at DP(B) after the transfer. As such, the customer would be charged for the load based on the monthly peak at DP(A) prior to or after the transfer period, plus the monthly peak at DP(B) which represents the combined load during the transfer period at DP(B).[2]

The financial impact of a double peak billing event can be magnified for a transmission-connected customer when they have a planned transmission outage that starts and ends in different calendar months or when multiple planned transmission outages are required in a given year. However, it is also worth noting that not all load transfers for transmission-connected customers with multiple DPs result in double peak billing events. Double peak billing will not occur when the additional load from the transfer does not contribute to the monthly peak load at the impacted DP for UTR billing purposes, or when the load is transferred for the full duration of the billing period, meaning there is no customer demand from the DP from which the load is transferred from for the duration of a billing period (this instance of load transfer is further discussed in Section 1.3 below).

With respect to the description of Issue 4 in the Notice for this proceeding, Hydro One notes the following:

- Double peak billing impacts transmission-connected customers irrespective of whether the load transfer event is initiated by the transmitter or the transmission-connected customer. It is the assumption in this Background Report that the solution will be applicable to both instances.
- Hydro One observes that as described in the Notice, Issue 4 includes only planned outages and as a result, planned outages are the focus of this background report. However, double peak billing events can and do occur in circumstances of both planned and unplanned transmission outages. While unplanned outages are beyond the control of transmitters and customers and do not always result in double peak billing events, Hydro One notes that clarification from the OEB as to

[2] For transmission-connected customers, double peak billing impacts Uniform Transmission Rates (including Network, Line Connection, and Transformation Connection charges) paid to the IESO.

the treatment of unplanned outages in the context of the current proceeding will help avoid future customer complaints and confusion.

- Although double peak billing events can impact both transmission-connected and distribution-connected customers (i.e. there is a parallel concern on the distribution side) which is particularly impactive for LDCs that have both transmission and distribution DPs, the focus of this background report is transmission-connected customers based on the OEB's scope. However, Hydro One has included in Appendix B three examples (5, 6, and 7) of how double-peak billing events impact distribution-connected customers.
- It is Hydro One's view that, for the following two reasons, the distribution issues will also need to be addressed either in parallel to or after the transmission issues are addressed as part of the current proceeding: First, from a consistency perspective a decision in respect of transmission-connected customers can be applied on the distribution side, provided that customers who may be impacted by the decision are involved in the proceeding. Second, as explained in detail in Sections 1.4.2.2, 1.4.3.2, and 1.4.4.2 below, there is an anomalous/unfair outcome for customers if double-peak billing issues are resolved for transmission-connected customers but not for distribution-connected customers.

Appendix A illustrates the impacts of a double peak billing event on a transmission-connected customer. Appendix B provides real examples of instances of double peak billing which have led to certain customer complaints being received by Hydro One.

1.3 WHO IS IMPACTED?

The transmission-connected customers most likely to experience double peak billing events are LDCs, as approximately 70% of LDCs have multiple DPs. While approximately 25% of large commercial and industrial transmission-connected customers have multiple transmission DPs, many are not located such that load could be transferred between transmission DPs so as to result in double peak billing events.[3]

[3] Certain transmission-connected LDCs and transmission-connected Commercial and Industrial customers with only one transmission-connected DP may have another source of supply through connection to the distribution system (essentially multiple DPs).

Double peak billing events result in incremental billing costs for those customers with the ability to transfer load between their multiple transmission DPs, which are costs that they would not otherwise incur absent these transmission outages. Although transmission-connected LDCs can incur these additional billing costs, they have established variance accounts[4] to track variances between the transmission charges they have paid to the Independent Electricity System Operator (IESO) and the transmission charges they have collected from their customers and are required, at a later date, to recover all tracked variances from or return them to their distribution customers, as applicable. As such, the cost impacts of double peak billing events, when experienced by LDCs, are ultimately borne by their distribution customers. Unlike LDCs, large commercial and industrial transmission-connected customers with multiple transmission DPs and who experience double peak billing events do not have the option of recovering the additional charges arising from double peak billing events and therefore bear any additional costs directly.

In Hydro One's experience, there have been several occasions during which concerns about additional charges from double peak billing events from impacted LDCs have caused delays in planned maintenance and capital work. Such delays can lead to further deterioration in asset condition, which can have safety and reliability implications, as well as increase the associated maintenance and capital costs.

Under the current billing practice, the only way to completely avoid double peak billing charges for transmission-connected customers, while maintaining the power supply, would be to precisely align the start and the end of the planned transmission outage with the start and end of the billing period, that is hour 00 of the first day and hour 24 of the last day of each calendar month. However, this practice keeps the DP unnecessarily out of service for a full month, which in turn increases the reliability risk.

While in most cases double peak billing charges cannot be completely eliminated, it is possible in some circumstances to minimize these charges by coordinating the work so

[4] Account 1584 RSVA – Retail Transmission Network Charge, and Account 1586 RSVA – Retail Transmission Connection Charge

that planned outages are taken when electricity demand is lowest (e.g. on weekends or evenings). However, this requires completing the work outside normal business hours, which can increase the associated costs, cause delays related to completion of the required work and may create safety concerns. Additionally, planned transmission outages can last a number of days, and in those instances would not always result in reduction to double peak billing.

1.4 POTENTIAL OPTIONS TO ADDRESS THE ISSUE

Hydro One notes that any proposed solutions to address the double peak billing issue should meet the following two objectives:

i. Avoid levying the additional transmission charges related to double peak events or ensure refunding of the additional charges incurred by the affected customers; and
ii. All transmitters should be able to fully collect their OEB-approved revenue requirement.

The following options could be considered to address the issue of double peak billing:

1.4.1 OPTION 1 – MAINTAIN STATUS QUO

As stated in the introduction, under the current billing methodology, transmission-connected customers are billed based on a monthly peak at each DP. Under this option, such customers would continue to bear the cost impact of double peak billing arising from load transfers between a customer's DPs during a planned transmission outage.

1.4.1.1 ADVANTAGES OF OPTION 1

- No change is required to the IESO processes or current billing practices.
- In the view of the OEB in the Original UTR Decision, the current practice was seen to follow the user-pays principle as transmission-connected customers with more than one DP were seen as receiving the benefit of increased reliability and should as a result expect to pay for this type of reliability.
- No additional costs or administrative efforts are required to modify the current billing practices and methodology.

1.4.1.2 DISADVANTAGES OF OPTION 1

- The current billing approach does not address the double peak billing concerns.

1.4.2 OPTION 2 - BILL BY CUSTOMER, INSTEAD OF BY DP

Under this approach, transmission charges would be calculated based on each customer's aggregated demand from all of their DPs, for a given time interval. In other words, transmission charges would be calculated at the customer level, rather than the current practice of billing at each DP. As discussed in the introduction, this billing approach was previously considered and rejected by the OEB in the Original UTR Decision.

1.4.2.1 ADVANTAGES OF OPTION 2

- This billing approach addresses the double peak billing concerns.

1.4.2.2 DISADVANTAGES OF OPTION 2

- Customers with multiple DPs[5] may gain unfair advantage because of a diversity of demand across their DPs. This is because different DPs may experience peak demand at different times. In this case the aggregated demand for the customer could be less than the sum of the peak demand at each DP resulting in lower charges for the customer. This revenue deficit from the lower aggregated demand will need to be made up by higher rates, shifting costs to the customers with single DP.
- While all transmission-connected load customers pay the Network Charge, customers who own their Line and/or Transformation Connection assets do not pay these charges. Currently, there are some transmission-connected customers with multiple DPs who own Line/Transformation assets at some of their DPs. Aggregating the demand at customer level will require additional consideration to make sure customers are not charged for the demand supplied by assets they own.
- Would involve significant effort for the IESO including updates to its billing and settlement systems. Hydro One notes that confirmation and input from the IESO

[5] Approximately 40% of transmission-connected load customers have multiple DPs.

will be needed as part of this proceeding with respect to the scope and cost of this work.

- Would require significant updates to the UTR schedule.
- Currently, Hydro One Distribution's large customers in the Sub-Transmission (ST) rate class are billed by DP, to be consistent with the transmission billing practices. Adopting the proposed approach of billing by customer for transmission-connected customers only, would create an anomalous outcome for distribution-connected customers as explained below:
  - Under the proposed approach, transmission-connected customers will not be subjected to additional transmission charges during a double peak event.
  - In a double peak billing event, the impacted ST customer will continue to pay additional amounts in Retail Transmission Service Rates (RTSRs) to the host distributor.[6]
  - The difference between transmission charges paid to the IESO and RTSR revenues collected from distribution customers are tracked in variance accounts. When these variance account balances are disposed of, the additional RTSR revenues related to the double peak billing event will be distributed among all distribution customers of the host distributor which would be unfair to the ST customer impacted by the double peak billing event.

1.4.3 OPTION 3 - REVISE THE DEFINITION OF THE TRANSMISSION CHARGE DETERMINANTS

Under this approach, charge determinants used to establish UTRs and bill transmission charges would be redefined to exclude the impact of planned transmission outages on customers with multiple DPs. This represents a change to the current methodology to establish UTRs and bill transmission charges which does not adjust for double peak billing

[6] In addition to the RTSR charges, the customer will also incur additional ST volumetric distribution charges due to the double peak billing event.

events. In other words, the historical charge determinants have included the impact resulting from the “double peak” events.

1.4.3.1 ADVANTAGES OF OPTION 3

- Customers would not be charged by the IESO for double peak events.

1.4.3.2 DISADVANTAGES

- Hydro One assumes that this will require significant time and effort to design and implement a well-defined process for identifying double peak billing situations and determining the load transferred between affected DPs over the duration of the planned outage. Hydro One notes that confirmation and input from the IESO will be needed as part of this proceeding with respect to the scope and cost of this work.
- Hydro One further assumes that significant changes would be required to the IESO’s billing and settlement systems and processes in order to calculate the charge determinants applicable to transmission customers experiencing double peak billing events (i.e. charge determinants would not be based just on meter readings adjusted for embedded load, as per the current process). Here too, Hydro One notes that confirmation and input from the IESO is critical in order to understand the impact and changes needed to IESO systems and processes.
- There is no historical data set for transmission charge determinants excluding double peak billing events and therefore there is no historical baseline that could be used for setting future charge determinants forecasts that exclude double peak billing events. It is not clear the effort that would be required – or if it is even possible – to accurately remove the impact of double peak events from the historical charge determinant data.
- Adjusting the charge determinants to remove the impact of double peak billing events would result in a reduction in the charge determinants used to calculate UTR rates, which would result in a corresponding increase in the UTR rates applicable to all transmission-connected customers.

- The extent to which future double peak billing events are accurately captured in the charge determinant forecast might result in over or under recovery of costs associated with such events.
- Would require significant changes to the UTR schedule.
- As mentioned in Section 1.4.2.2 above, adopting this approach for only transmission-connected customers would create an anomalous/unfair outcome for Hydro One Distribution's ST customers.

1.4.4 OPTION 4 –TRACK DOUBLE PEAK BILLING IMPACT IN A DEFERRAL ACCOUNT

Under this approach, the current UTR charge determinant definition and practices of billing based on a monthly peak at each DP will not change. However, transmission-connected customers that are charged for double peak billing events will receive a refund directly from their transmitter for the associated double peak charges. More specifically, this approach includes the following detailed steps:

- Transmission-connected customers that are affected by each double peak billing event will receive refund directly from their transmitter.
- The affected transmitter will track the refunded amounts in a deferral account.
- Other transmitters' UTR revenues are not impacted, and they are not involved in the refund/recovery process (i.e. their payments from the IESO are not affected).
- In its next rebasing application, the affected transmitter will bring forward the deferral account balances for disposition.

1.4.4.1 ADVANTAGES OF OPTION 4

- This option addresses the concerns related to double peak billing.
- No changes are required to the IESO's processes and current billing practices.
- No changes are required to the UTR schedule.
- As the transmitter issues refunds directly to the affected transmission customers, there are no administrative settlement requirements imposed on the other unaffected transmitters or the IESO.

- No change required to existing load forecasting process. The IESO does not need to track demand data without double peak events, as transmitters will continue to use metered data (unadjusted) as basis for producing charge determinant forecast.
- There is no risk of under or over recovery of costs associated with double peak events as the exact amounts provided as refunds to the customers are recovered through the disposition of the deferral account at a future date.
- Provides clear visibility to the magnitude of double peak billing events as part of the regulatory process for disposition of the associated deferral account.

1.4.4.2 DISADVANTAGES OF OPTION 4

- Additional administrative burden for the affected transmitters in terms of:
    - New business processes and coordination between various internal and external teams to keep track of every eligible double peak event; and
    - Calculating and issuing refunds to customers and tracking the refund amounts in the deferral account.
- Methodology for calculating the refund amount will need to be established.
- As mentioned in Section 1.4.2.2 above, adopting this approach for only transmission-connected customers would create an anomalous/unfair outcome for Hydro One Distribution's ST customers.

1.4.4.3 OTHER CONSIDERATIONS FOR OPTION 4

- The IESO bills for transmission service charges based on the IESO registered wholesale meter readings. Double peak events are reflected in the meter readings. Double peak billing refund calculation requires estimation of meter readings for the load transferred from one DP to another DP. These readings can be estimated either by installing temporary devices that are not approved by Measurement Canada (e.g., Electronic Recorder Ammeter (ERA)) or by using historical readings. As mentioned above, methodology for calculating the refund will need to be established.
- The costs related to double peak billing will be small when compared to total provincial transmission revenue requirement. Therefore, in order to ensure that transmitters recover the costs associated with refunding customers experiencing

double peak billing events, it will be necessary for UTRs to be rounded to 4 decimal places.

APPENDIX A

Impacts of a Double Peak Billing Event on a Transmission-Connected Customer

Two billing scenarios for a transmission-connected LDC with multiple DPs are presented below for illustrative purposes to show how they may be impacted by double peak billing events.[7]

The current demand-based charges for transmission-connected customers at each DP are charged as follow:

Network Service Rate	Higher of: a) DP's coincident peak demand in the hour of the month when the total hourly demand of all customers is highest for the month; or b) 85% of the DP's peak demand during any hour 7 AM to 7 PM business days.
Line Connection Service Rate	Any-time DP's peak demand
Transformation Connection Service Rate	Any-time DP's peak demand

** Demand is measured as the energy consumed during the clock hour per DP*

SCENARIO 1 – NO LOAD TRANSFER BETWEEN DPS

- An LDC has 2 transmission DPs.
- Normal monthly peak for DP(A) is 2MW and DP(B) is 3MW.
- For DP(A) and DP(B), for Network Service Rate, 85% of the DP's peak demand during any hour 7 AM to 7 PM business days is higher than DP's coincident peak.

The monthly Transmission chargers for the LDC without any load transfers between DP(A) and DP(B) are presented in **Table 1** below.

[7] The IESO transmission bill estimates are based on the OEB-approved UTR Order EB-2023-0222 for Network, Line Connection, and Transformation Connection service rates.

Table 1 - Estimated Monthly Transmission Charges for an LDC (No Load Transfer)

	$/kW/month	Charge Determinant[8]	Transmission Charges at DP(A)		Transmission Charges at DP(B)	
			NCP (kW)	**Transmission Charges ($)**	**NCP (kW)**	**Transmission Charges ($)**
Network Service Rate	$5.78	85% NCP	2,000	$9,826	3,000	$14,739
Line Connection Service Rate	$0.95	NCP	2,000	$1,900	3,000	$2,850
Transformation Connection Service Rate	$3.21	NCP	2,000	$6,420	3,000	$9,630
TOTAL				**$18,146**		**$27,219**
Total DP(A)+DP(B)	**$45,365**					

SCENARIO 2 – MID-MONTH LOAD TRANSFER BETWEEN DPS

- An LDC has 2 transmission DPs.
- Normal monthly peak for DP(A) is 2MW and DP(B) is 3MW.
- For DP(A) and DP(B), for Network Service Rate, 85% of the DP's peak demand during any hour 7 AM to 7 PM business days is higher than DP's coincident peak.
- Load transfer was initiated due to scheduled transmission outage (either customer or transmitter initiated) mid-month and concluded the same month.
- Load transfer results in $18,146 of incremental charges related to double peak billing.

The monthly Transmission chargers for the LDC with load transfers between DP(A) and DP(B) mid-month are presented in **Table 2** below.

[8] NCP = Non-Coincident Peak

1 **Table 2 - Estimated Monthly Transmission Charges for LDC (With Load Transfer)**

	$/kW/month	Charge Determinant[9]	Transmission Charges at DP(A)		Transmission Charges at DP(B)	
			NCP (kW)	Transmission Charges ($)	NCP (kW)	Transmission Charges ($)
Network Service Rate	$5.78	85% NCP	2,000	$9,826	5,000	$24,565
Line Connection Service Rate	$0.95	NCP	2,000	$1,900	5,000	$4,750
Transformation Connection Service Rate	$3.21	NCP	2,000	$6,420	5,000	$16,050
TOTAL				**$18,146**		**$45,365**
Total DP(A)+DP(B)	**$63,511**					
Incremental Charges Due to Double Peak Billing Event Total Scenario 2 – Total Scenario 1	**$18,146**					

[9] NCP = Non-Coincident Peak

APPENDIX B

Examples of Double Peak Billing Events

TRANSMITTER-INITIATED LOAD TRANSFER IMPACTING A TRANSMISSION-CONNECTED LDC

Example 1

An LDC is transmission connected at two Municipal Transformer Stations, ("MTS A" and "MTS B"). In 2016, in order to reconductor transmission lines supplying MTS A, Hydro One Transmission requested that the LDC transfer its load from MTS A to MTS B. The LDC refused the load transfer request due to double peak billing concerns. In response to the LDC's concerns, Hydro One Transmission made arrangements (which had staffing implications) to transfer the load at midnight on the last day of a month, and to transfer the load back at midnight on the last day of the following month, which would enable the LDC to avoid double peak billing for the month during which the load transfer was required. However, Hydro One staff were unable to start the load transfer at midnight on the required day due to inclement weather conditions.

Example 2

For the same LDC as in Example 1, in 2021 Hydro One Transmission required the load to be transferred from one station to the other to enable Hydro One to perform one day of work on its transmission line. In an effort to avoid double peak billing, the load transfer was started at midnight on the last day of a month and was planned to end at midnight on the last day of the following month. However, due to an unplanned outage that occurred on the line supplying the station that was temporarily being used to supply the LDC's entire service area, the LDC transferred the load back to the station which was planned to be offline for the balance of the month. This occurred just over a week into the month, resulting in double peak billing charges.

Example 3

Hydro One Distribution ("Customer A") and two other LDCs ("Customer B" and "Customer C") are transmission-connected LDCs, which are connected at and served by the same transmission station. In December 2023, in order to replace non-compliant equipment, Hydro One Transmission requested that all three LDCs transfer their loads away from the transmission station. At the request of impacted customers, Hydro One Transmission delayed the load transfer from December 2023 to February 2024 and the load transfer was started at midnight on the last day of January 2024 and ended at midnight on the last day of February 2024 to avoid double peak billing charges.

Example 4

Hydro One Distribution (“Customer A”) and another LDC (“Customer B”) are transmission-connected LDCs, which are connected at and served by the same transmission station. In order to refurbish the transmission station over an approximately 14-month period between 2017 and 2018, Hydro One Transmission initiated several short-term load transfers within the transmission station whereby Customer A’s DP load was supplied from Customer B’s DP, and vice versa, resulting in double peak billing charges for both Customer A and Customer B.

TRANSMISSION-CONNECTED CUSTOMER-INITIATED LOAD TRANSFER (FROM THE TRANSMISSION SYSTEM TO THE DISTRIBUTION SYSTEM) IMPACTING THE TRANSMISSION-CONNECTED CUSTOMER AND THE TRANSMISSION-CONNECTED LDC

Example 5

An industrial customer (“Customer A”) is a transmission-connected customer at Customer-owned Transmission Station (“CTS-A”). Hydro One Distribution (“Customer B”) is a transmission-connected LDC at another transmission station (“TS-B”). In order to perform maintenance activities at CTS-A, between August 03 and August 05, 2022, Customer A initiated a short-term load transfer from CTS-A to Customer B’s TS-B. As a result of this load transfer, Customer A incurred delivery charges related to double peak billing charged by Customer B, and Customer B incurred additional transmission chargers related to double peak billing charged by the IESO.

TRANSMITTER-INITIATED LOAD TRANSFER IMPACTING A TRANSMISSION-CONNECTED LDC AND ITS EMBEDDED LDC SUPPLIED BY THE SAME TRANSMISSION STATIONS

Example 6

Hydro One Distribution ("Customer A") is a transmission-connected LDC at the two transmission stations TS-A and TS-B. An LDC ("Customer B") is a distribution-connected LDC served by Hydro One Distribution ("Customer A") at TS-A and TS-B. In December 2017, in order to perform maintenance activities at TS-A, Hydro One Transmission initiated a load transfer from TS-A to TS-B. As a result of this load transfer, Customer B incurred distribution delivery charges related to double peak billing charged by Customer A and Customer A incurred additional transmission charges related to double peak billing charged by the IESO.

HOST DISTRIBUTOR-INITIATED OUTAGE IMPACTING ITS EMBEDDED LDC

Example 7

Hydro One Distribution ("Customer A") is a transmission-connected LDC at a transmission station ("TS-A"). An LDC ("Customer B") is a distribution-connected LDC served by Customer A at TS-A. Customer B is also a transmission-connected LDC at another transformer station ("TS-B"). In March 2021, in order to replace a distribution system pole, Customer A requested Customer B to transfer their load from TS-A to TS-B. As a result of this load transfer, Customer B incurred additional transmission related double peak billing charges charged by the IESO.

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ISSUES 5 & 6 – BASIS FOR BILLING ENERGY STORAGE FACILITIES AND GROSS LOAD BILLING THRESHOLDS FOR RENEWABLE AND NON-RENEWABLE GENERATION

1.0 INTRODUCTION

Due to the overlap between issues 5 and 6, which both relate to gross load billing, and their shared historical context, Hydro One has addressed these issues together. In Appendix A of the OEB's December 20, 2022 letter regarding Phase 2 of the Generic Hearing on UTRs, the OEB describes issues 5 and 6 as follows:

> The UTR is not explicit on whether energy storage facilities should continue to be treated as non-renewable generating units with a threshold for gross load billing of 1 MW for the transformation and connection rate pools paid for by transmission customers. Clarification is currently provided to transmission customers through OEB guidance on a case-by-case basis (the "**Storage Billing Issue**").
>
> There has been some uncertainty around the application of gross load billing exemptions by transmission customers for renewable and non-renewable generation. Clarification is currently provided to transmission customers through OEB guidance (the "**GLB Thresholds Issue**").

In its October 27, 2023 Notice of Hearing, the OEB elaborates on these issues as follows:

> <u>Issue 5: Storage Billing Issue</u>
> The UTR establishes a gross load billing threshold of greater than 1 MW for non-renewable generating units and greater than 2 MW for renewable generating units for the transformation and connection rate pools paid for by transmission customers. The scope of this issue is to review whether the 1 MW and 2 MW thresholds are still the appropriate thresholds. The scope also includes considering the appropriate billing threshold for energy storage facilities. The scope of this issue does not include billing for distribution or whether energy storage facilities should be considered renewable or non-renewable (or something else) for purposes of gross load billing. The scope of this issue has been revised by the OEB from how it was first described in the October 15, 2021 Notice of Hearing for Phase 1 of the generic hearing on UTR-related issues.

> Issue 6: GLB Thresholds Issue
> Beyond the question of appropriate gross load billing thresholds, set out in issue 5, there has been some uncertainty around the application of those thresholds to transmission customers – for example, with respect to incremental capacity resulting from a generator refurbishment. Clarification is currently provided to customers through OEB guidance.

As further discussed below, the rules for gross load billing were first established at the time of market opening when the OEB rendered its May 26, 2000 Decision with Reasons in RP-1999-0044 (the "Original UTR Decision"). The rules for gross load billing were last reviewed and updated as part of the Transmission System Code Phase 1 Policy proceeding (RP-2002-0120). As such, in response to concerns and questions raised about current practices, there is a need to review whether the rules for gross load billing reflected in the UTR Schedule continue to be appropriate or should be updated.

1.1 HISTORICAL CONTEXT

In Section 3.2 of the Original UTR Decision, the OEB explained that generation which is not connected to the transmission system and connected behind the meter that measures the electricity supplied from regulated transmission facilities to a transmission customer, is referred to as "embedded generation". Embedded generation reduces demand on the transmission system. Given that the costs of transmission infrastructure are largely fixed, there was a need for the OEB to consider whether transmission customers who reduce their load supplied from the transmission system by installing embedded generation should continue to be charged for the sunk costs of the transmission system that was built to supply their original load (gross load billing), or they should not bear those sunk costs (net load billing).

Under *net load billing*, the charges for a transmission customer are calculated on the basis of a charge determinant that is measured on the meter(s) reading the load customer draws from the regulated transmission system.

Under *gross load billing*, the charges for a transmission customer are calculated as they are under net load billing plus the load supplied by any embedded generation.

The OEB determined that net load billing shall apply when calculating Network Service Charges because in that circumstance (among other reasons) it is fair, more practical and simpler to apply.[1] However, with respect to Line Connection Service and Transformation connection Service charges, the OEB determined that gross load billing shall apply, but only for load customers who connect new embedded generation.[2] Load supplied by existing embedded generation, for which required approvals were obtained before October 30, 1998, when the *Energy Competition Act, 1998*, came into being, shall continue to be billed on a net load basis.[3]

Furthermore, the OEB determined that, for reasons of administrative simplicity and cost efficiency, new embedded generation under 1 MW serving existing load should be exempt from gross load billing and billed on a net load basis. The OEB considered that gross load billing requires the installation of separate metering for the embedded generation and the incorporation of this data into the IESO's billing and settlement processes, which would create costs and complexities that would likely outweigh any benefits from billing customers with smaller embedded generators on a gross load basis. The OEB also considered that such generators would be exempt from IESO dispatch and scheduling requirements.[4]

As stated above, the issue of gross load billing was considered again in RP-2002-0120, along with other amendments to the Transmission System Code and related matters, as part of a broader policy review conducted by the OEB. In its Decision with Reasons, dated June 8, 2004, the OEB found that transmission customers with new embedded generation should continue to be subject to the rate treatment established in the Original UTR Decision, namely net load billing for Network Charges and gross load billing for Connection (and Transformation) charges, except for embedded generation of 1 MW per unit or less where net load billing applies for both Network and Connection (and Transformation) charges. However, the OEB decided to

[1] Original UTR Decision, Section 3.2.33
[2] Original UTR Decision, Section 3.2.39
[3] Original UTR Decision, Section 3.3.3
[4] Original UTR Decision, Section 3.2.44

> …increase the qualifying limit for exemption from gross billing from 1 MW per unit to 2 MW per unit for renewable generation installations. This increase reflects a societal interest in increasing the proportion of renewable generation in the overall generation mix in the province, and the technical reality that the output of some renewable source generation equipment has advanced from under 1 MW per unit to just under 2 MW per unit. It is intended that renewable energy projects comprised of generation units producing 2 MW or less per unit will be eligible for net billing charges on relevant connection facilities. The Board notes that there was a request to increase this qualifying limit to 20 MW. The Board rejects this proposal as being excessive.[5]

For the purpose of defining renewable generation, the OEB adopted the definition of Renewable Generating Facility being used by the Ontario government at the time, which refers to a facility that generates electricity from sources such as wind, solar, Biomass, Bio-oil, Bio-gas, landfill gas, or water.[6]

In its Decision and Order in EB-2005-0241, dated December 8, 2005, approving transmission rates for Great Lakes Power Limited, the OEB approved new Uniform Transmission Rates (UTR) effective from January 1, 2006. The Transmission Rate Schedules for those UTR (the “UTR Schedule”), attached as Appendix A to the Decision and Order, included both the 1 MW threshold for non-renewable generation and the 2 MW threshold for renewable generation in Part G thereof under the heading “Embedded Generation”. Since the RP-2002-0120 Decision was issued, no updates have been made to the gross load billing rules.[7]

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[5] RP-2002-0120, Decision and Order, Para 230

[6] RP-2002-0120, Decision and Order, Para 231

[7] The UTR schedule was updated in 2017 as a part of Board Order EB-2017-0280 issued on November 23, 2017, to clarify the gross load billing rules applied to incremental capacity amount associated with any refurbishments to a generator unit approved after October 30, 1998. The current UTR Schedule is filed as Board Order EB-2023-0222, issued on January 18, 2024.

1.2 DETAILED DESCRIPTION OF THE ISSUES

In Hydro One's view, there are several issues related to the GLB Thresholds Issue and the Storage Billing Issue. These issues are described and discussed in detail below.

1.2.1 ISSUE 1 - APPLICATION OF GROSS LOAD BILLING TO "EMBEDDED GENERATOR UNITS"

In determining whether a transmission customer who installs embedded generation behind their meter is subject to gross load billing, the UTR Schedule states that the thresholds for renewable and non-renewable generation apply to "customer demand that is supplied by an embedded generator unit." The UTR Schedule does not define "unit" or "embedded generator unit", nor are these terms are defined in the Transmission System Code (TSC), the *Electricity Act* or the *Ontario Energy Board Act*.

Section 11.1 of the TSC does, however, clearly distinguish between generation *facilities* on the one hand, and generating *units* on the other, where it states that each of the requirements in that section "applies regardless of ownership of the generation facility, the voltage at which the generation facility is connected, the location of the generation facility, the size or number of units of generation capacity, . . ." Therefore, in the TSC, "generation facility" and "unit of generation capacity" have different meanings and it is understood that generation facilities include individual units of generation capacity. Furthermore, the IESO Market Rules define "generation unit" to mean "the equipment that actually generates electricity, together with all related equipment essential to its functioning as a single entity."

Statements made in the OEB's Decision with Reasons in RP-2002-0120 also seem to acknowledge that a customer's embedded generation could include more than one generator unit and that the size of each individual generator unit shall be used to determine whether gross load billing is applied. Specifically, the OEB noted that "the output of some renewable source generation equipment has advanced from under 1 MW per unit to just under 2 MW per unit" and that "it is intended that *renewable energy projects comprised of* *generation units producing 2 MW* or less per unit will be eligible for net billing charges on relevant connection facilities. [emphasis added][8]

In view of the above, there appears to be an acceptance and understanding from a regulatory standpoint that, in the context of generation facilities, a 'unit' is a component of a generation facility and refers to each individual set of equipment or devices that is capable of functioning independently to generate electricity. Depending on their needs, a customer's embedded generation facility could be designed to include one or more units. Based on the foregoing, it is reasonable to assume that the use of the term 'generator unit' was intentional and indicative of a specific meaning, i.e. that gross load billing eligibility shall be assessed based on the size of each individual generator unit, which together comprise the generation facility. Hydro One practice therefore has been, and continues to be, to assess gross load billing eligibility by applying the thresholds in the UTR Schedule on a 'per-unit' basis as opposed to a 'facility' basis.

For commercial and industrial customers seeking to reduce their demand under the Industrial Conservation Initiative, the way in which the gross load billing rules have been established has effectively provided customers with an opportunity to size the units of their embedded generation facility to avoid gross load billing settlement charges. Hydro One is aware of several instances in which a customer has installed multiple generator units and the aggregate rated capacity of these units (i.e. the installed capacity of the embedded generation *facility*) exceeds the applicable gross load billing threshold. However, since none of the individual generator units exceeds the threshold on its own, the load supplied by these units has been, and continues to be, exempt from gross load billing charges.

As a transmitter, Hydro One must apply the gross load billing rules as they have been set out in the UTR Schedule. Hydro One also recognizes that its application of the gross load billing rules may be resulting in unintended consequences. As a result, customers whose total installed generation capacity exceeds the gross load billing threshold would not be

[8] RP-2002-0120, Decision with Reasons, Section 5.2.1.

exempt from gross load billing charges if the installed capacity of their generation facility was used as the basis for assessing gross load billing eligibility.

1.2.2 ISSUE 2 - APPLICATION OF GROSS LOAD BILLING TO EMBEDDED SOLAR GENERATION

The current approach of using the generator unit size as the basis for applying gross load billing also raises questions as to how inverter-based embedded generation should be assessed. In general, a solar generation facility will consist of a set of photovoltaic cell arrays that are connected through an inverter to produce electrical power. Often, a solar facility will be designed to include multiples sets of arrays, with each array having their own inverter. In such an arrangement, each array/inverter set could be viewed as independent from an operational standpoint and would represent a single generator unit.

Hydro One's practice has been to use the capacity of the inverter for each array/inverter set within an embedded solar generation facility to define an individual generator unit. In its transmission revenue requirement proceeding for years 2020-2022 (EB-2019-0082), Hydro One indicated that, when providing data to the IESO for billing Line Connection and Transformation Connection Service charges, an inverter capacity greater than or equal to 1 MW was being used as a cut-off for applying gross load billing to embedded solar generation. When questioned about the application of this threshold, Hydro One responded that, in its experience, inverter capacity for solar generation is typically small (under 0.5 MW) and, as result, the threshold limit is irrelevant.[9] As a result, no customers with embedded solar generation are being billed on a gross load basis. For clarity, it should be noted that the GLB Thresholds Issue, as it pertains to embedded solar generation, applies only to customers of a transmission-connected Local Distribution Company (LDC). This is because solar generation facilities are almost exclusively connected to the distribution system or behind the meter of distribution-connected customers. Based on Hydro One's data, other transmission-connected load customers (i.e. non-LDC customers) do not install embedded solar generation.

[9] See EB-2019-0082, Undertaking JT 2.34 – Q18.

The fact that embedded solar generation is currently exempt from gross load billing (based on Hydro One's practice of using the inverter capacity of each array/inverter set within an embedded solar generation facility to define an individual generator unit) highlights an important need to review the threshold applicable to solar generation and whether the approach of using the inverter size to define the size of a generator unit is appropriate and achieves the intended objectives contemplated in the Original UTR Decision and the RP-2002-0120 Decision. By applying the 2 MW threshold on a per-unit basis, Hydro One has determined that 1,268 MW of embedded solar generation is currently exempt from gross load billing charges. In contrast, more than half of the installed embedded wind generation capacity is being billed on a gross load basis. This is due to the fact that wind generating units tend to be larger than 2 MW.

1.2.3 ISSUE 3 - APPLICATION OF GROSS LOAD BILLING TO ENERGY STORAGE FACILITIES

An energy storage facility is unique in its ability to function both like a load or a generator. When an energy storage facility is charging, it withdraws energy from the grid like a load customer but when it is discharging, it injects energy into the grid like a generator customer. Because of its ability to switch operating modes instantly in response to a control signal, energy storage has many potential applications and can provide a wide range of services, including peak shaving and demand response.

The UTR Schedule does not clarify whether an embedded generator unit includes an embedded energy storage unit. Furthermore, the UTR Schedule does not specify whether or not, in the circumstances where an embedded energy storage unit reduces a transmission customer's non-coincident peak in the same manner that an embedded generation unit would, energy storage should be treated as generation for the purpose of assessing gross load billing eligibility.

In the absence of further guidance on these aspects, Hydro One has adopted the practice of applying gross load billing to embedded energy storage because energy storage is typically deployed by customers to reduce their non-coincident peak demand. Since storage does not rely on a renewable process for injecting power, Hydro One has applied the non-renewable generation unit threshold (1 MW) for assessing gross load billing eligibility. Where appropriate, Hydro One has relied on its practice of using the inverter to delineate units within a storage facility, consistent with its approach for treating inverter-based generation. In December 2018, Hydro One met with OEB staff to inform them of its intention to treat energy storage the same as non-renewable generation for assessing gross load billing eligibility. The OEB did not object to Hydro One's proposed approach for treating energy storage and there have been no further discussions with the OEB in relation to this matter.

In its transmission revenue requirement proceeding for years 2020-2022 (EB-2019-0082), Hydro One described its treatment of energy storage and the applicability of the 1 MW threshold for gross load billing. Hydro One explained its approach for treating energy storage like generation and that applying this threshold is appropriate given that the energy provided by storage is not created from a renewable process.[10] In its Decision and Order, the OEB noted that Hydro One was treating energy storage as non-renewable generation for gross load billing purposes, although the terms of the UTR Schedule do not mention energy storage facilities. The OEB also noted staff's concern with formalizing this practice without further consideration by the OEB. On this issue, the OEB determined that:

> Affected customers should be consulted prior to amending the Terms and Conditions of the UTR schedule with respect to Hydro One's proposal to continue treating behind the meter energy storage facilities as embedded non-renewable generation. Hydro One has indicated that customers will not be impacted by these changes, and the changes are intended to clarify the current rules and practice. Rather than waiting three years to incorporate this clarification in the Terms and Conditions, the OEB will consider these amendments in the proceeding for the 2021 revenue requirement, provided Hydro One can provide evidence that affected customers have been consulted. This review should be mechanistic if there are no concerns raised by affected customers.[11]

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[10] EB-2019-0082, Undertaking JT 2.34 – Q18.
[11] OEB, Decision and Order, p. 175, EB-2019-0082, April 23, 2020.

In its 2021 transmission revenue requirement proceeding, Hydro One indicated that "[it] has not consulted customers on any proposed changes to the UTR schedule, and proposes that it would be more appropriate to address this issue in a generic proceeding dealing with UTR matters".[12] The OEB's UTR decisions for 2021 and subsequent years do not make reference to the treatment of energy storage from a gross load billing perspective. Hydro One has therefore continued its practice of applying gross load billing to embedded energy storage as explained in EB-2019-0082.

Some customers have questioned Hydro One's practice of applying gross load billing to energy storage and have cited, among other things, concerns about the additional metering costs and the appropriateness of gross load billing customers who are participating in the Industrial Conservation Initiative. In March 2022, the IESO published a report, "Update on the Status of Obstacles to Storage Resources in Ontario", and noted the following issue:

> The storage community also expressed concern with respect to gross load billing for the line and transformation connection components of the transmission charges. Specifically, the concern is that storage resources experience a lower threshold for triggering gross load billing than embedded renewable resources.[13]

The IESO report acknowledged that, in the absence of a specific rate class for energy storage, "transmitters and distributors must interpret the existing framework to determine the applicability of transmission and distribution charge to energy storage resources."[14] The IESO recommended that the OEB lead further discussions on this issue in its proceeding to address issues related to UTRs.

Despite the concerns raised, customers have generally accepted Hydro One's approach for applying gross load billing to embedded storage units. Hydro One is not aware of any specific complaints made by customers to the OEB in regard to its treatment of energy

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[12] EB-2020-0202, A-4-1.
[13] IESO, Update on the Status of Obstacles to Storage Resources in Ontario, p.11, March 31, 2022
[14] IESO, Update on the Status of Obstacles to Storage Resources in Ontario, p.11, March 31, 2022

storage nor has Hydro One been asked by the OEB to comment on its approach for gross load billing related to energy storage in response to a specific or general complaint. Hydro One is also not aware of any specific guidance issued by the OEB in respect of this matter.

1.2.4 ISSUE 4 – THRESHOLD LIMITS FOR GROSS LOAD BILLING

In its October 27, 2023 Notice of Hearing, the OEB indicated that it would review the renewable and non-renewable generation thresholds for gross load billing eligibility to determine if they remain appropriate. In the Original UTR Decision, the OEB acknowledged that, in principle, all embedded generation could cause stranding of transmission system assets. However, after considering the customer cost and administrative complexity associated with implementing gross load billing, the OEB determined that new embedded generation under 1 MW should be exempt from gross load billing. In Section 3.2.44 of the Original UTR Decision, the OEB stated the following:

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

The use of this threshold for assessing renewable generation was revisited in RP-2002-0120. In its Decision with Reasons, the OEB determined that the threshold should be increased to 2 MW per unit for renewable generation installations. In Section 2.5.1 of its Decision with Reasons, the OEB states that:

> This increase reflects a societal interest in increasing the proportion of renewable generation in the overall generation mix in the province, and the technical reality that the output of some renewable source generation equipment has advanced from under 1MW per unit to just under 2MW per unit.

If the OEB intends to review whether the current gross load billing thresholds for renewable and non-renewable embedded generation remain appropriate, the OEB should consider whether its assessment of the factors noted above remains valid and if other factors should now be considered in assessing the appropriateness of the current thresholds. For example, the OEB may want to review whether the incorporation of meter data from embedded generation into the IESO settlement process is administratively complex or burdensome on the market operator and the OEB may want to examine whether the cost of installing an additional gross load billing meter would deter customers from installing embedded generation and at what point does this cost become excessive for the customer. In establishing the unit size thresholds for embedded generation and other load displacement technologies, the OEB will need to balance fairness, practicality and cost.

1.3 OTHER ISSUES FOR CONSIDERATION

In addition to the central issues described above, which relate directly to the Storage Billing Issue and the GLB Thresholds Issue in this proceeding, Hydro One believes that there are additional considerations related to these issues for which parties may wish to request clarifications or resolutions, or gain a greater understanding of, in this proceeding. These are described in the subsections below.

1.3.1 CALCULATING INCREMENTAL CAPACITY FOR GROSS LOAD BILLING ELIGIBILITY

The UTR Schedule states that gross load billing should be applied to "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." Consistent with its approach of assessing gross load billing eligibility based on the generator unit size,[15] Hydro One applies gross load billing to the incremental increase in capacity on a "per-unit" basis of any embedded generator unit refurbished after 1998.

In one case, the customer of an LDC, which is connected to Hydro One's transmission system, disagreed with Hydro One's methodology for calculating the incremental capacity that should be subject to gross load billing following a refurbishment. The transmission-

[15] See Terms and Conditions in the current UTR Schedule, EB-2023-0222, issued on January 18, 2024.

connected LDC and their customer argued that the incremental capacity should be calculated at the facility level and not at the unit level, which in this case would have resulted in a lower incremental capacity value. Clarification was sought by Hydro One from OEB staff on this matter through an Industry Relations Enquiry (IRE-2021-0210).

In their response, OEB staff disagreed with Hydro One's calculation methodology and indicated that "Hydro One's proposed approach is not consistent with the UTR Schedule or the OEB decision in RP-1999-0044." OEB staff indicated that gross load billing should be applied to the incremental capacity of the refurbished station and that "load supplied by the grid and load lost from the grid is proportionate to the station's overall capacity, rather than the capacity of individual generation units." Lastly, OEB staff indicated that there may be a need to clarify the language used for establishing the gross load billing rules in the UTR Schedule.

OEB staff's response to Hydro One in this particular example is inconsistent with the treatment of embedded generation on a unit basis, as discussed above, and it highlights the need for clarity regarding the intended application of gross load billing rules in the UTR Schedule to refurbished or expanded legacy generation facilities. For further details related to IRE-2021-0210, please refer to Appendix A.

1.3.2 AVAILABILITY OF GROSS LOAD BILLING EXEMPTIONS

If a transmission customer installs embedded generation, the UTR Schedule does not provide a transmitter with any discretion or flexibility in the application of the gross load billing rules. In certain limited circumstances, it may be appropriate for a transmitter to exempt a customer from gross load billing.

One such example is when a customer applies to connect a new load or increase their existing load but the transmission system is constrained and cannot accommodate their requested connection or full load. If the customer installs embedded generation to meet their supply needs, it may be appropriate to exempt their embedded generation from gross load billing in full or to the extent the embedded generation is required to meet their supply needs. Hydro One recently submitted an Industry Relations Enquiry seeking permission to exempt a customer from gross load billing in such a scenario and is awaiting a response.

Another example where discretion may be warranted is when a customer installs embedded generation for the sole purpose of “peak shaving” and mitigating their Class A Global Adjustment charges under the Industrial Conservation Initiative. In this scenario, the embedded generation is run only at select times to reduce the customer’s non-coincident peak demand during anticipated Ontario peak demand hours over a base period. Where embedded generation is being deployed in this manner, this results in only a marginal impact to the customer’s monthly non-coincident peak demand. Therefore, in this circumstance, it may be appropriate to exempt such embedded generation from gross load billing.

1.3.3 IMPLICATIONS FOR GROSS LOAD BILLING RULES FOR DISTRIBUTION

Hydro One Distribution and certain LDCs have approval to apply gross load billing of sub-transmission and retail transmission service rates for distribution customers that install new embedded generation. The principles that inform gross load billing at the distribution level have largely been adopted from the Original UTR Decision and the UTR Schedule. Since the gross load billing of the transmission-connected LDC results in a trickle down effect (in terms of how these charges are then collected from distribution customers who cause these charges), proper consideration must be given to how gross load billing is implemented at both the transmission and distribution levels to ensure that the outcomes are as intended and consistent between transmission and distribution (to the extent that the OEB determines that consistency is appropriate). Furthermore, if and to the extent that changes are made to gross load billing at the transmission level as a result of this proceeding, it may be appropriate to consider the need for equivalent changes to be made to gross load billing at the distribution level, either as part of this proceeding or some other proceeding, to maintain regulatory alignment and consistency.

1.4 POTENTIAL OPTIONS TO ADDRESS THE ISSUES

1.4.1 ISSUE 1 - APPLICATION OF GROSS LOAD BILLING TO "EMBEDDED GENERATOR UNITS"

Option #1

- Maintain current rules and thresholds for gross load billing in the UTR Schedule.
- Reiterate the applicability of gross load billing on a 'per unit' basis.

Pros

- Continuing to assess gross load billing on a 'per unit' basis is consistent with Hydro One's understanding of the gross load billing rules as set out in the UTR Schedule and how the rules have historically been applied by Hydro One.
- Confirmation from the OEB would formally address longstanding questions and complaints regarding gross load billing applicability.

Cons

- Assessing eligibility for gross load billing on a 'per unit' basis will continue to enable some transmission-connected customers with embedded generation to design their facilities to avoid gross load billing settlement.
- Most embedded generation facilities installed by customers do not typically include a single unit and are comprised of multiple units. Therefore, assessing gross load billing based on the size of individual units does not seem appropriate if this treatment would allow for an entire facility to be exempt.
- Certain types of embedded generation may have an advantage if it is easier to install a smaller sized generator unit.
- Given that government programs and initiatives have driven and will continue to drive customer deployment of embedded generation facilities and other load displacement technologies, this will become a pain point for the entire sector if the issue is not properly addressed.
- May result in other transmission-connected customers disproportionately bearing the cost of sunk transmission connection costs resulting from the installation of

embedded generation that do not meet gross load billing thresholds when treated on a generation unit basis.

- Would effectively exempt embedded solar generation facilities from gross load billing whereas other renewable facilities, such as wind or hydro, may not be exempt.

Option #2

- Revise the rules in the UTR Schedule to clarify that the thresholds for gross load billing apply to the aggregate installed capacity of all embedded generator units installed by the customer at that connection point to the system.

Pros

- Addresses a longstanding issue related to the manner in which gross load billing is being applied from a principled perspective, particularly with respect to embedded solar generation facilities.
- Results in a fair treatment of all types of renewable generation.
- Would eliminate any ambiguity or misunderstanding regarding the application of the gross load billing rules.
- Most transmission-connected customers would receive a small reduction in their transmission charges.

Cons

- More customers who install embedded generation would be subject to gross load billing. As a result, these customers would incur additional metering costs for gross load billing and would pay higher transmission charges than they would have under the current rules. This could discourage the installation of new embedded generation.
- The OEB would need to decide how existing embedded generation, which is exempt from gross load billing based on the size of the generator unit(s), shall be treated. Since the current rules permanently exempt generation that received connection approval before 1998 from gross load billing, the OEB would need to

decide if a similar exemption should be granted to exempt generation impacted by this rule change.

1.4.2 ISSUE 2 – APPLICATION OF GROSS LOAD BILLING TO EMBEDDED SOLAR GENERATION

Option #1

- Clarify applicability of the gross load billing thresholds to embedded generation that employs inverters, such as embedded solar generation.

<u>Pros</u>

- Would eliminate any uncertainty regarding the treatment of inverter-based embedded generation on a 'per-unit' basis.
- The gross load billing rules would not enable customers who deploy inverter-based embedded generation to be exempt from gross load billing more easily than customers who deploy other types of embedded generation.
- If the current gross load billing thresholds are reduced for inverter-based embedded generation, transmission customers would pay lower transmission charges.

<u>Cons</u>

- More customers, who install an inverter-based embedded generation facility, would be subject to gross load billing. These customers would incur costs to install metering for gross load billing and would pay higher transmission charges than they would have under the current rules.
- The OEB would need to decide how existing inverter-based embedded generation, which is exempt from gross load billing based on the current application of the gross load billing rules, shall be treated. Since the current rules permanently exempt generation that received connection approval before 1998 from gross load billing, the OEB would need to decide if a similar exemption should be granted to exempt generation impacted by a revision to the threshold limit.

1.4.3 ISSUE 3 – APPLICATION OF GROSS LOAD BILLING TO ENERGY STORAGE FACILITIES

Option #1

- Clarify that energy storage should be exempt from gross load billing in the UTR Schedule.

Pros

- Clarifies the rules for gross load billing customers who install energy storage facilities.
- Customers installing energy storage would not have to pay for additional metering costs to implement gross load billing.
- Would simplify administration of IESO settlement processes.

Cons

- Hydro One would need to change its current practices for billing customers with embedded energy storage, which would result in other customers bearing higher transmission charges.
- Customers with existing embedded energy storage, who had to incur metering costs to implement gross load billing, would incur costs associated with removing this equipment.
- Gross load billing would continue to favour one technology over another when, principally, their objective is the same. Treatment of storage in this manner would be seen as unfair.

Option #2

- Clarify that gross load billing rules in the UTR Schedule do apply to energy storage installations and clarify the threshold applicable to energy storage installations.

<u>Pros</u>

- Hydro One's current practice of gross load billing customers with embedded energy storage would not change.
- Provides clarity and certainty for all customers installing energy storage facilities.
- Gross load billing rules would be technologically agnostic and would treat energy storage customers the same as other embedded generation.

<u>Cons</u>

- Establishing a specific threshold for storage, if different than the current threshold being used, would result in billing changes for new and existing customers.
- Customers with energy storage would continue to be billed on a gross load basis which could discourage future deployment of energy storage by customers.

1.4.4 ISSUE 4 – THRESHOLD LIMITS FOR GROSS LOAD BILLING

Option #1

- Review factors that were used to establish the existing threshold limits.
- Adjust gross load billing threshold limits accordingly.

<u>Pros</u>

- Would confirm that the factors, namely administrative complexity and customer cost, and the assessment of these factors in establishing the current thresholds remains valid or should be updated to reflect current data and experience.
- A review would consider the higher number of smaller sized generator units that have connected since the thresholds were originally established.
- A review would consider how specific load displacement technologies are being deployed and whether this is a factor that should be considered in setting the thresholds.

<u>Cons</u>

- Updates to transmitter billing systems may be required to reflect changes.

- Updates to IESO billing and settlement processes may be required to reflect changes.
- Could require OEB to address whether it is appropriate to permanently exempt customers with legacy embedded generation.
- Addressing this issue could require significant analysis.

1.5 REQUEST FOR CLARIFICATION ON OTHER ISSUES FOR CONSIDERATION

1.5.1 CALCULATING INCREMENTAL CAPACITY FOR GROSS LOAD BILLING ELIGIBILITY

For customers that refurbish an embedded generation unit, for which approvals were received before 1998, where the refurbishment increases the installed capacity, it would be helpful in Hydro One's view if the OEB were to clarify whether the incremental capacity eligible for gross load billing should be calculated on a per unit or facility basis. Clear guidance from the OEB to the industry would ensure that there is a consistent interpretation of how this issue should be treated. In providing this guidance, the OEB should also consider the treatment of previously exempt generation.

1.5.2 AVAILABILITY OF GROSS LOAD BILLING EXEMPTIONS

There may be instances where a customer reduces their demand by installing embedded generation but the monthly transmission charges paid by the customer to the transmitter for the cost of supplying them is not affected. Gross load billing should be applied practically and achieve the objectives set out in the Original UTR Decision. The OEB should consider providing certain flexibility in applying the gross load billing rules where a situation merits such treatment and, where possible and appropriate, the OEB should provide clear direction as to how these situations should be addressed.

1.5.3 IMPLICATIONS OF GROSS LOAD BILLING RULES FOR DISTRIBUTION

The OEB should maintain consistency in terms of how gross load billing principles and practices are implemented at the transmission and distribution levels. This is necessary to ensure that transmission costs are recovered fairly from those customers connected to the distribution system who are driving these costs. If the OEB proposes to change the gross load billing rules in the UTR Schedule, the OEB should clarify how these changes would impact or alter gross load billing of distribution customers.

APPENDIX A

IRE-2021-0210

[Note: Certain details have been modified or omitted in an effort to conceal the identity of the customer]

Dear,

This is our response to the enquiry you submitted to Industry Relations.

Initial enquiry: "Hi Industry Relations,

Following on the advice received from OEB Staff, Hydro One is seeking concurrence from the OEB that it is properly applying Gross Load Billing (GLB) in the following scenario in accordance with its approved UTR. The details of the scenario and Hydro One's interpretation of how GLB should be applied in this scenario are explained below.

Scenario Details

Load Customer is connected to another LDC's system, and the LDC is a Hydro One transmission customer
Load Customer has an existing (pre-1998) facility consisting of four 800 kW generating units and is replacing the four units with two new 2,000 kW units

Hydro One's Approach for Applying GLB

Per the current UTR tariff, GLB shall be applied to the incremental capacity associated with any unit refurbished after 1998 and the incremental capacity is 1 MW or greater for non-renewable generation
Based on the current UTR, Hydro One proposes to apply GLB on a generation unit basis and not at a facility level
Since the incremental capacity of each unit is 1,200 kW, which is greater than 1 MW, GLB would apply to each of the new units
The total incremental capacity subject to GLB would therefore be 2,400 kW

At Issue

The LDC connected to Hydro One's system and their load customer disagree with Hydro One's methodology for calculating the added incremental capacity that should be subject to GLB
The LDC and the customer believe that the incremental capacity subject to GLB should be considered at the facility level
Therefore, since the previous installed capacity of the facility was 3,200 kW (4*800 kW) and the refurbishment will result in a new installed capacity of 4,000 kW (2*2,000 kW), they believe that the total incremental capacity subject to GLB would be the

difference in the installed capacity or 800 kW

Hydro One's Position

As currently stated, Hydro One's UTR clearly states that GLB shall be applied to the incremental capacity associated with any refurbished unit – and not at the facility level
Hydro One is simply following the rules as they are stated in its UTR; In reviewing whether GLB is applicable in any scenario, Hydro One has consistently applied GLB on a unit basis
Since the load customer has reduced the number of units of its plant and increased the size of the new units, the installed incremental capacity subject to GLB is higher than if they left the same number of units and increased the size
A review of the current GLB rules in Hydro One's UTR should be undertaken and consideration should be given to updating the GLB rules such that they would apply on a facility basis as opposed to on a unit basis

Thank you for your attention on this matter."

Thank you for your IRE:

In summary and as outlined in greater detail below, OEB staff's view is that Hydro One should apply Gross Load Billing to the incremental generator station capacity of 800 kW resulting from the refurbishment of the generator station's units.

In OEB staff's opinion, applying Gross Load Billing to the incremental station capacity which results from the refurbishment is consistent with the OEB's policy on Gross Load Billing with respect to embedded generation, which is rooted in addressing the impacts of embedded generation to potentially strand transmission assets. This view is also consistent with an interpretation of "incremental capacity" as meaning the net result of the capacity additions and reductions resulting from a refurbishment, not just the additions.

Hydro One proposes to apply Gross Load Billing on a generator unit basis rather than on a station basis in the scenario described in the IRE. Since the incremental capacity of each new unit is 1,200 kW (2,000 kW - 800 kW = 1,200 kW), which is greater than 1 MW, Gross Load Billing would apply to each of the new units. Under Hydro One's proposal, the total incremental capacity subject to Gross Load Billing would be 2,400 kW (2 x 1,200 kW = 2,400 kW).

However, in OEB's staff's view, Hydro One's proposed approach is not consistent with the UTR or the OEB's decision in RP-1999-0044 for transmission rates that loads installing new generation or incremental generation should be charged on a Gross Load Billing basis to compensate for the impact of the reduced load.

In OEB staff's view the correct approach for Hydro One to apply the Gross Load Billing to the incremental capacity of the station described in its IRE is on the incremental capacity of the refurbished station. Load supplied by the grid and load lost from the grid is proportionate to the station's overall capacity, rather than the capacity of individual generation units.

Hydro One has suggested there may be ambiguity or even inconsistency in UTR language on Gross Load Billing for embedded generation. OEB staff may propose to review the UTR in the future to clear up the language.

OEB staff is of the view that the correct approach to Gross Load Billing in the scenario outlined by Hydro One is on a value of 800 kW representing the incremental capacity the load is installing, and not the 2,400 kW proposed by Hydro One.

The response to this enquiry represents the views of Ontario Energy Board (OEB) staff, based on the specific set of facts provided to us in the enquiry and the legal and regulatory requirements currently in place – if the facts or the requirements were to change, the response might be different. The response is not offered as and does not constitute legal advice, and is not binding on the OEB.

Thank you for your enquiry. I hope you find this information helpful.

Regards,
Industry Relations

The response to this enquiry represents the views of Ontario Energy Board (OEB) staff, based on the specific set of facts provided to us in the enquiry and the legal and regulatory requirements currently in place – if the facts or the requirements were to change, the response might be different. The response is not offered as and does not constitute legal advice, and is not binding on the OEB.