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**BY EMAIL AND RESS**

October 24, 2022

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

Dear Ms. Marconi,

**EB-2021-0110 – Custom IR Application (2023-2027) for Hydro One Networks Inc. Transmission and Distribution ("Hydro One") – Settlement Proposal**

A settlement conference was held in respect of the above noted application from August 15 to August 24, 2022 in accordance with Procedural Order No. 5. Hydro One and the following intervenors (collectively, the Parties) participated in the Settlement Conference:

- Anwaatin Inc.
- Association of Major Power Consumers in Ontario
- Canadian Manufacturers & Exporters
- Canadian Union of Skilled Workers
- Consumers Council of Canada
- Distributed Resource Coalition
- Energy Probe Research Foundation
- Environmental Defence
- Ice River Sustainable Solutions
- London Property Management Association
- Michipicoten First Nation
- Ontario Sustainable Energy Association
- Pollution Probe
- Power Workers' Union
- Quinte Manufacturers Association
- School Energy Coalition
- Society of United Professionals
- Vulnerable Energy Consumers Coalition

On behalf of the Parties, attached please find a Settlement Proposal covering all issues for the Commissioners' review. The Settlement Proposal includes the following:

- Proposed Settlement Agreement
- Attachment 1 – Supporting Schedules – Transmission
- Attachment 2 – Supporting Schedules – Distribution
- Attachment 3 – Draft Accounting Orders

Hydro One will update Attachments 1 and 2 by mid-November to reflect the OEB's Cost of Capital Parameters and Inflation Factors for 2023. At the same time, Hydro One will reflect two changes agreed-to by the Parties in Attachments 1 and 2 as follows: (i) Hydro One will remove the Overhead Capitalization Adjustment (as that term is defined in the Proposed Settlement Agreement); and (ii) Hydro One will adjust the load forecast to be consistent with the load forecast included in Tables 7 and 8 in the Proposed Settlement Agreement.

An electronic copy of the settlement proposal and excels has been submitted using the Board's Regulatory Electronic Submission System.

Sincerely,

Kathleen Burke

cc. EB-2021-0110 parties

**EB-2021-0110**

**ONTARIO ENERGY BOARD**

**IN THE MATTER OF** the *Ontario Energy Board Act*, 1998, S.O. 1998, c. 15 (Sched. B) (the "Act");

**AND IN THE MATTER OF** an application by Hydro One Networks Inc. ("Hydro One") for an Order or Orders made pursuant to section 78 of the Act, approving or fixing just and reasonable rates for the transmission and distribution of electricity.

**HYDRO ONE NETWORKS INC.**

**SETTLEMENT PROPOSAL**

**October 24, 2022**

## LIST OF TABLES

## A. OVERVIEW

### 1. *Introduction*

This Settlement Proposal is filed with the Ontario Energy Board ("**OEB**") in connection with Hydro One Networks Inc.'s ("**Hydro One**") Custom Incentive Rate ("**Custom IR**") application made under section 78 of the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, Schedule B (the "**Act**") seeking approval for changes to the rates that it charges for electricity transmission and distribution, beginning January 1, 2023, and for each following year through to December 31, 2027 (the "**Application**"). The OEB assigned proceeding number EB-2021-0110 to the Application.

As set forth herein, the Settlement Proposal contains a comprehensive settlement of all issues within the Application.

### 2. *Background*

Hydro One filed the Application on August 5, 2021, and the OEB published the Notice of Hearing on August 19, 2021. On September 17, 2021, the OEB issued Procedural Order No. 1 which, among other things, (i) approved requests for intervenor status, (ii) determined that the Export Transmission Service ("**ETS**") Rate will be considered through a separate, generic proceeding on Uniform Transmission Rates (as part of EB-2021-0243), rather than as part of the Application, and (iii) set out a schedule of procedural steps, which provided for the consideration of confidential filings, determination of the issues list, interrogatories, OEB staff and intervenor evidence, a technical conference and a settlement conference.

In Procedural Order No. 2, issued on October 25, 2021, the OEB determined, among other things, that a 'blue page update' to the pre-filed evidence, reflecting 2021 audited financial information, would not be required.

Hydro One received interrogatories from OEB staff and intervenors in late October 2021 and filed its responses to interrogatories on November 29, 2021. A transcribed technical conference was held from December 13-17, 2021, following which Hydro One filed its undertaking responses on January 5, 2022. Shortly thereafter, on January 13, 2022 in Procedural Order No. 3, the OEB approved the issues list for the purposes of the proceeding (the "**Approved Issues List**").

On February 4, 2022, Hydro One filed a letter with the OEB advising that it was not able to proceed with the settlement conference scheduled for February 7, 2022. Hydro One explained that it was unable to enter into meaningful discussions at that time because of its obligation, under the OEB's rules, to amend its application to reflect material changes to Operations, Maintenance and Administration ("**OM&A**") and capital expenditures arising from unprecedented inflationary pressures. In its Decision and Procedural Order No. 4, issued February 18, 2022, the OEB postponed the settlement conference and placed the Application in abeyance, effective February 4, 2022, until such time that Hydro One filed its updates to the Application and the OEB issued a new procedural schedule.

On March 31 and April 8, 2022, Hydro One filed updates to the Application to reflect the impact of inflation on its proposed investment plans, modifications to certain assumptions in the load forecasts, a proposal for deferred recovery of the incremental revenue requirement arising from the inflation update and the shortfall in revenue requirement due to updates made to the CDM assumptions in its load forecasts to the next rate period, update to its pre-filed evidence regarding the Transmission External Revenues Variance Account, as well as 2021 actuals for capital and OM&A expenditures and in-service additions. Unless otherwise specified, the figures presented in this Settlement Proposal are based on the numbers included in Hydro One's evidence updates dated March 31 and April 8, 2022.

In Procedural Order No. 5, issued on April 14, 2022, the OEB set out, among other things, an updated schedule and hearing process. Hydro One received interrogatories on the Application updates from OEB staff and intervenors on May 2, 2022 and filed responses to those interrogatories on May 16, 2022. A transcribed technical conference was held from May 31 to June 1, 2022, following which Hydro One filed undertaking responses on June 16, 2022.

Pursuant to Procedural Order No. 5, the econometric expert retained by Hydro One (Clearspring Energy Advisors) and the econometric expert retained by OEB staff (Pacific Economics Group), conferred with each other for the purposes of narrowing issues and identifying points of agreement or disagreement in connection with their respective benchmarking and productivity research and recommendations relating to the parameters of Hydro One's proposed Custom IR revenue escalation formulas. After completing their conferral process, the experts filed a joint report on June 13, 2022. Responses from the experts to interrogatories on their joint report were filed July 14, 2022.

In Procedural Order No. 6, issued on June 2, 2022, the OEB permitted cost eligible intervenors to file claims for costs incurred to the end of the Technical Conference on Hydro One's March 31, 2022 and April 8, 2022 evidentiary updates.

**3. *Settlement Process***

In accordance with Procedural Order No. 5, a Settlement Conference was convened on August 15, 2022 and continued until August 24, 2022. The Settlement Conference was conducted in accordance with the OEB's *Rules of Practice and Procedure* (the "**Rules**") and the *Practice Direction on Settlement Conferences* ("**Practice Direction**").

Ken Rosenberg acted as facilitator for the Settlement Conference.

Hydro One and the following 18 intervenors (the "**Intervenors**") participated in the Settlement Conference:[1]

- Anwaatin Inc. (Anwaatin)
- Association of Major Power Consumers in Ontario (AMPCO)
- Canadian Manufacturers & Exporters (CME)
- Canadian Union of Skilled Workers (CUSW)
- Consumers Council of Canada (CCC)
- Distributed Resource Coalition (DRC)
- Energy Probe Research Foundation (EP)
- Environmental Defence (ED)
- Ice River Sustainable Solutions (IRSS)
- London Property Management Association (LPMA)
- Michipicoten First Nation (MFN)
- Ontario Sustainable Energy Association (OSEA)
- Pollution Probe (PP)
- Power Workers' Union (PWU)
- Quinte Manufacturers Association (QMA)
- School Energy Coalition (SEC)
- Society of United Professionals (SUP)
- Vulnerable Energy Consumers Coalition (VECC)

Hydro One and the Intervenors are collectively referred to below as the "**Parties**".

OEB staff also participated in the Settlement Conference. The role adopted by OEB staff is set out in the Practice Direction. Although OEB staff is not a party to this Settlement Proposal, as noted in the Practice Direction, OEB staff who participated in the Settlement Conference are bound by the same confidentiality and settlement privilege requirements that apply to the Parties to the proceeding.

Notwithstanding any other wording in this Settlement Proposal, the PWU, CUSW, IRSS, and the SUP are neither supporting nor opposing any elements of this Settlement Proposal. Where this Settlement Proposal refers to the "Parties" agreeing to or accepting something, that does not include the PWU, CUSW, IRSS or SUP.

[1] The following six approved intervenors in the proceeding did not participate in the Settlement Conference: ENWIN Utilities Ltd., Essex Powerlines Corporation, Independent Electricity System Operator, Richard Gruchala (Independent Participant), Ontario Power Generation Inc, and Ontario Federation of Agriculture.

**4. *Settlement Proposal Preamble***

This document comprises the Settlement Proposal and is presented jointly to the OEB by the Parties. This document is called a "Settlement Proposal" because it is a proposal by the Parties to the OEB to settle the issues in this proceeding identified as settled in this Settlement Proposal. It is termed a proposal as between the Parties and the OEB. However, as between the Parties, and subject only to the OEB's approval of this Settlement Proposal, this document is intended to be a legal agreement, creating mutual obligations, and binding and enforceable in accordance with its terms. As set forth later in this Preamble, this Settlement Proposal is subject to a condition subsequent: that if it is not accepted by the OEB in its entirety, then unless amended by the Parties, it is null and void and of no further effect. In entering into this Settlement Proposal, the Parties understand and agree that, pursuant to the Act, the OEB has exclusive jurisdiction with respect to the interpretation and enforcement of the terms hereof.

The Parties acknowledge that the Settlement Conference, including any settlement information relating thereto, is privileged and confidential in accordance with the Practice Direction. The Parties understand that confidentiality in that context does not have the same meaning as confidentiality in the OEB's *Practice Direction on Confidential Filings* and that the rules of the latter document do not apply. Instead, in the Settlement Conference, and in this Settlement Proposal, the Parties have interpreted "confidential" to mean that the documents and other information provided during the course of the Settlement Conference, the discussion of each issue, the offers and counteroffers, and the negotiations leading to the settlement – or not – of each issue during the Settlement Conference and during the preparation of this Settlement Proposal are strictly privileged and without prejudice. None of the foregoing is admissible as evidence in this proceeding, or otherwise, with one exception: the need to resolve a subsequent dispute over the interpretation of any provision of this Settlement Proposal. Further, the Parties shall not disclose those documents or other settlement information to persons who were not attendees at the Settlement Conference. However, the Parties agree that "attendees" is deemed to include, in this context, persons who were not in attendance via video conference at the Settlement Conference but were (a) any persons or entities that the Parties engaged to assist them with the Settlement Conference (including the preparation of this Settlement Proposal); and (b) any persons or entities from whom they have sought instructions with respect to the negotiations, in each case provided that any such persons or entities have agreed to be bound by the same confidentiality provisions as the Parties.

In accordance with Section 11 of the Practice Direction, it is the expectation of the Parties that OEB staff will file a submission with the OEB commenting on two aspects of the Settlement Proposal: whether the Settlement Proposal represents an acceptable outcome from a public interest perspective, and whether the accompanying explanation and rationale is adequate to support the Settlement Proposal.

This Settlement Proposal is organized based on the Key Components of Settlement (Part B, below) and in accordance with the Approved Issues List (Part C, below). Part C of this Settlement Proposal provides a brief description of each of the settled issues, together with references to the evidence submitted for the record in this proceeding. The Parties agree that references to the "evidence" in this Settlement Proposal shall, unless the context otherwise requires, include, in addition to the Application, the written responses to interrogatories and technical conference undertakings, and other components of the record up to and including the date hereof, including additional information provided by the Parties in this Settlement Proposal and the appendices to this document (the "**Appendices**").

The supporting Parties for each settled issue agree that the evidence in respect of that settled issue is sufficient in the context of the overall settlement to support the proposed settlement, and the sum of the evidence in this proceeding provides an appropriate evidentiary record to support acceptance by the OEB of this Settlement Proposal.

There are Appendices and Attachments to this Settlement Proposal which provide further support for the Settlement Proposal. The Parties acknowledge that the Appendices and Attachments were prepared by Hydro One. While the Parties have reviewed the Appendices and Attachments, the Parties are relying on the accuracy of those Appendices and Attachments and the underlying evidence in entering into this Settlement Proposal.

The final agreements of the Parties following the Settlement Conference are set out below. The Parties explicitly request that the OEB consider and accept this Settlement Proposal as a package. None of the matters in respect of which a settlement has been reached is severable. Numerous compromises were made by the Parties with respect to various matters to arrive at this Settlement Proposal. If the OEB does not accept the Settlement Proposal in its entirety, then there is no agreement, unless the Parties agree, in writing, that the balance of this Settlement Proposal may continue as a valid settlement subject to any revisions that may be agreed-upon by the Parties.

It is further acknowledged and agreed that none of the Parties will withdraw from this agreement under any circumstances, except as provided under Rule 30.05 of the Rules.

In the event that the OEB directs the Parties to make reasonable efforts to revise the Settlement Proposal, the Parties agree to use reasonable efforts to discuss any potential revisions, but no Party will be obligated to accept any proposed revision. The Parties agree that all of the Parties who took a position on a particular issue must agree with any revised Settlement Proposal as it relates to that issue, or take no position on the issue, prior to its resubmission to the OEB for its review and consideration as a basis for making a decision.

Unless otherwise expressly stated in this Settlement Proposal, the settlement of any particular issue in this proceeding and the positions of the Parties in this Settlement Proposal are without prejudice to the rights of the Parties to raise the same issue and/or to take any position thereon in any other proceeding, whether or not Hydro One is a party to such proceeding, provided that no Party shall take a position that would result in the Settlement Proposal not applying in accordance with the terms contained herein.

In this Settlement Proposal, where any of the Parties "accept" the evidence of Hydro One, or "agree" to a revised term or condition, including a revised budget or forecast, then, unless expressly stated to the contrary, the words "for the purpose of settlement of the issues herein" shall be deemed to qualify that acceptance or agreement.

## 5. *Settlement Proposal Summary*

The Parties are pleased to advise that they have reached a complete settlement on all aspects of the Approved Issues List, as summarized in the following table and as described in greater detail in Parts B and C, below.

| | |
|---|---|
| **"Complete Settlement"** means an issue for which complete settlement was reached by all Parties, and if this Settlement Proposal is accepted by the OEB, none of the Parties (including Parties who take no position on that issue) will adduce any evidence or argument during the hearing (if any) in respect of the specific issue. | Issues Settled:<br><br>**ALL** |
| **"Partial Settlement"** means an issue for which there is partial settlement, as Hydro One and the Intervenors who take any position on the issue were able to agree on some, but not all, aspects of the particular issue. If this Settlement Proposal is accepted by the OEB, the Parties (including Parties who take no position on the Partial Settlement) will only adduce evidence and argument during the hearing (if any) on the portions of the issue for which no agreement has been reached. | Issues Partially Settled:<br><br>**NONE** |
| **"No Settlement"** means an issue for which no settlement was reached. Hydro One and the Intervenors who take a position on the issue will adduce evidence and/or argument at the hearing on the issue (if any). | Issues Not Settled:<br><br>**NONE** |

The following summarizes, at a high level, the most significant elements of the Settlement Proposal, including with respect to the Custom IR frameworks, inflation assumptions, load forecast and deferred recovery, deferral and variance account disposition period, revenue requirement and bill impacts for Hydro One's Transmission and Distribution businesses. More detailed descriptions of the key components of settlement are set out in **Part B**, and descriptions of each of the settled issues, together with references to the evidence submitted for the record in this proceeding based on the Approved Issues List, are set out in **Part C**. The revenue requirement summary and rate and bill impacts are set out in the schedules in **Attachments 1** and **2** for Transmission and Distribution, respectively, and the Accounting Orders are set out in **Attachment 3** (collectively, the **"Supporting Schedules"**).

The Application and the supporting evidence provide extensive detail on Hydro One's Transmission and Distribution revenue requirements for the 2023 test year and Hydro One's Transmission and Distribution revenue requirements for 2024 to 2027, which are derived from the applicable Custom IR frameworks (the "**Custom IR Frameworks**"). The Parties, through negotiations, have agreed to modifications to Hydro One's proposed revenue requirements for Transmission and Distribution and the applicable Custom IR Frameworks. These include, among other things, reductions to capital expenditures and to OM&A

spending, as well as modifications to certain parameters to be used as part of the Custom IR Frameworks for calculating revenue requirements for 2024 to 2027.

With respect to the Custom IR Frameworks, the Parties accept Hydro One's proposed frameworks for each of Transmission and Distribution, with the following modifications:

- **Transmission:** the framework will include a Productivity Factor (X factor) of 0.15% (rather than 0% as proposed), and a Supplemental Stretch on Capital of 0.20% (rather than 0.15% as proposed);
- **Distribution:** the framework will include a Productivity Factor (X factor) of 0.45% consistent with the joint recommendation of the experts dated June 13, 2022 (rather than 0.30% as proposed), and a Supplemental Stretch on Capital of 0.20% (rather than 0.15% as proposed); and
- **Both Transmission and Distribution**: instead of disposing of ESM balances at Hydro One's next cost-based rate application, ESM balances for 2021-2024 will be disposed of in Hydro One's 2026 annual update applications.

With respect to inflation, the Parties have agreed that Hydro One's inflation assumptions will be those presented in its March 31, 2022 Evidence Update and that the inflation assumptions will not be further updated in this proceeding. The Parties have also agreed that Hydro One's load forecasts will be as presented in its March 31, 2022 Evidence Update subject to one modification, which is described below. Furthermore, the Parties have agreed that Hydro One will not defer its recovery of incremental approved revenue requirement amounts arising from its use of updated inflation assumptions and the revenue deficiency arising from updates made to the Conservation and Demand Management ("**CDM**") assumptions in its load forecasts, as proposed in Hydro One's March 31, 2022 Evidence Update.

Table 1 through Table 6 provide a summary of Hydro One's proposed Transmission and Distribution revenue requirements for 2023 and the revenue requirements for 2024-2027 derived from the applicable Custom IR Frameworks for Transmission and Distribution. The revenue requirement impact for 2023 by each component is presented under Section B highlighting the changes to each of the components resulting from this Settlement Proposal. Unless otherwise specified, the figures are based on the numbers included in Hydro One's evidence updates from March 31, 2022 and April 8, 2022. Attachment 1, Schedule 1.0 and Attachment 2, Schedule 1.0 include the revenue requirement summary for each of Transmission and Distribution respectively. The March 31, 2022 Evidence Update included a proposal (ultimately rejected in this Settlement Proposal) to update the revenue requirement at the Draft Rate Order ("**DRO**") stage to reflect the new inflation rate, but not to exceed a prescribed Inflation Forecast Cap of 10% cumulative inflation over 2022 and 2023.[2]

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[2] O-SEC-253 includes an illustrative example where the 10% inflation cap is met, hypothetically with a 7% inflation rate in 2022 and 3% inflation in 2023.

Overall, for Hydro One's Transmission business, this Settlement Proposal represents a reduction in revenue requirement of $17.4M in the 2023 rebasing year (and $250.0M in total over 2023-2027), with associated annual impacts as determined using the Custom Revenue Cap Index (the "**Custom RCI**" or "**RCI**") formula over the 2024-2027 rate period. The key elements contributing to this overall reduction in revenue requirement are described in Part B of this Settlement Proposal.

Overall, for Hydro One's Distribution business, this Settlement Proposal represents a reduction in revenue requirement of $14.5M in the 2023 rebasing year (and $232.6M in total over 2023-2027), with associated annual impacts as determined using the RCI formula over the 2024-2027 rate period. The key elements contributing to this overall reduction in revenue requirement are described in Part B of this Settlement Proposal.

**Table 1 - 2023 Settled Total Transmission Revenue Requirement ($M)**

| | **2023** |
|---|---:|
| **Proposed Transmission Revenue Requirement**[3] | 1,849.3 |
| **Settled Transmission Revenue Requirement** | 1,831.9 |
| **Difference** | **(17.4)** |

**Table 2 - 2023-2027 Settled Total Transmission Revenue Requirement**[4]

| **Year** | **Formula - Proposed** | **Transmission Revenue Requirement Proposed ($M)** | **Formula - Settled** | **Transmission Revenue Requirement Settled ($M)** | **Difference ($M)** |
|---|---|---:|---|---:|---:|
| 2023 | Cost of Service | 1,849.3 | Cost of Service | 1,831.9 | **(17.4)** |
| 2024 | 2023 Revenue Requirement x 1.0643 | 1,968.2 | 2023 Revenue Requirement x 1.0580 | 1,938.1 | **(30.1)** |
| 2025 | 2024 Revenue Requirement x 1.0482 | 2,063.0 | 2024 Revenue Requirement x 1.0410 | 2,017.6 | **(45.5)** |
| 2026 | 2025 Revenue Requirement x 1.0579 | 2,182.5 | 2025 Revenue Requirement x 1.0464 | 2,111.2 | **(71.3)** |
| 2027 | 2026 Revenue Requirement x 1.0386 | 2,266.6 | 2026 Revenue Requirement x 1.0330 | 2,180.9 | **(85.7)** |

[3] Exhibit O-01-02, Table 16
[4] Proposed amounts are presented based on Exhibit O-01-02, Tables 26 and 27

Table 3, below, shows the difference between Hydro One's proposed Transmission revenue requirement and the hypothetical revenue requirement where inflation for 2022 and 2023 was updated to Hydro One's proposed cumulative cap of 10%, as well as the difference between the Settled revenue requirement and the hypothetical revenue requirement where inflation for 2022 and 2023 was updated to Hydro One's proposed cumulative cap of 10%.

**Table 3 - 2023-2027 Proposed Total Transmission Revenue Requirement Vs. Proposed Total Transmission Revenue with 10% Inflation Cap Scenario Vs. Settled Total Transmission Revenue Requirement[5]**

| Year | Transmission Revenue Requirement Proposed ($M) | Transmission Revenue Requirement Proposed with 10% Inflation Cap Scenario ($M) | Difference ($M) | Transmission Revenue Requirement Settled ($M) | Difference Settled vs. Proposed with 10% Inflation Cap Scenario ($M) |
|---|---|---|---|---|---|
| 2023 | 1,849.3 | 1,860.3 | **11.0** | 1,831.9 | **(28.4)** |
| 2024 | 1,968.2 | 1,980.9 | **12.7** | 1,938.1 | **(42.8)** |
| 2025 | 2,063.0 | 2,078.0 | **15.0** | 2,017.6 | **(60.4)** |
| 2026 | 2,182.5 | 2,200.2 | **17.7** | 2,111.2 | **(89.0)** |
| 2027 | 2,266.6 | 2,286.6 | **20.0** | 2,180.9 | **(105.7)** |

**Table 4 - 2023 Settled Total Distribution Revenue Requirement ($M)**

| | **2023** |
|---|---|
| **Proposed Distribution Revenue Requirement[6]** | 1,669.1 |
| **Settled Distribution Revenue Requirement** | 1,654.6 |
| **Difference** | **(14.5)** |

[5] Interrogatory Response to O-SEC-253 where an illustrative example of 10% inflation cap is met, hypothetically with a 7% inflation rate in 2022 and 3% inflation in 2023.

[6] Exhibit O-01-02, Table 17

**Table 5 - 2023-2027 Settled Total Distribution Revenue Requirement[7]**

| Year | Formula - Proposed | Distribution Revenue Requirement Proposed ($M) | Formula - Settled | Distribution Revenue Requirement Settled ($M) | Difference ($M) |
|---|---|---|---|---|---|
| 2023 | Cost of Service | 1,669.1 | Cost of Service | 1,654.6 | **(14.5)** |
| 2024 | 2023 Revenue Requirement x 1.0505 | 1,753.3 | 2023 Revenue Requirement x 1.0440 | 1,727.3 | **(26.1)** |
| 2025 | 2024 Revenue Requirement x 1.0450 | 1,832.2 | 2024 Revenue Requirement x 1.0343 | 1,786.5 | **(45.8)** |
| 2026 | 2025 Revenue Requirement x 1.0560 | 1,934.8 | 2025 Revenue Requirement x 1.0470 | 1,870.4 | **(64.5)** |
| 2027 | 2026 Revenue Requirement x 1.0464 | 2,024.6 | 2026 Revenue Requirement x 1.0387 | 1,942.8 | **(81.8)** |

Table 6, below, shows the difference between Hydro One's proposed Distribution revenue requirement and the hypothetical revenue requirement where inflation for 2022 and 2023 was updated to Hydro One's proposed cumulative cap of 10%, as well as the difference between the Settled revenue requirement and the hypothetical revenue requirement where inflation for 2022 and 2023 was updated to Hydro One's proposed cumulative cap of 10%.

**Table 6 - 2023-2027 Proposed Total Distribution Revenue Requirement Vs. Proposed Total Distribution Revenue with 10% Inflation Cap Scenario Vs. Settled Total Distribution Revenue Requirement[8]**

| Year | Distribution Revenue Requirement Proposed ($M) | Distribution Revenue Requirement Proposed with 10% Inflation Cap Scenario ($M) | Difference ($M) | Distribution Revenue Requirement Settled ($M) | Difference Settled vs. Proposed with 10% Inflation Cap Scenario ($M) |
|---|---|---|---|---|---|
| 2023 | 1,669.1 | 1,684.5 | **15.4** | 1,654.6 | **(29.9)** |
| 2024 | 1,753.3 | 1,771.0 | **17.7** | 1,727.3 | **(43.7)** |
| 2025 | 1,832.2 | 1,852.1 | **19.9** | 1,786.5 | **(65.6)** |
| 2026 | 1,934.8 | 1,957.4 | **22.6** | 1,870.4 | **(87.0)** |
| 2027 | 2,024.6 | 2,049.7 | **25.1** | 1,942.8 | **(106.9)** |

[7] Proposed amounts are presented based on Exhibit O-01-02, Tables 28 and 29

[8] Interrogatory Response to O-SEC-253 where an illustrative example of 10% inflation cap is met, hypothetically with a 7% inflation rate in 2022 and 3% inflation in 2023.

With respect to deferral and variance account disposition for Transmission and Distribution, the Parties have agreed with Hydro One's proposed methodology and amounts for disposition as revised throughout the course of the proceeding, subject to the modification that disposition for Transmission will be over a 1-year period in 2023 rather than over a 5-year period as proposed and disposition for Distribution will be over a 3-year period from 2023 to 2025 rather than over a 5-year period as proposed. Additionally, the balances for Transmission and Distribution have been further adjusted to reflect the calculation of the Accelerated CCA Sub-Account based on actual additions as agreed by the Parties.

As noted above, the Parties have agreed on one modification to the methodologies that Hydro One has used to determine its Transmission and Distribution load forecasts. Specifically, the Parties agree that Hydro One will modify the load forecasts for each of Transmission and Distribution by reducing the assumptions for incremental achievable potential CDM by 100% for each of 2023 and 2024, and by 35% for each of the years from 2025-2027, relative to that which was included in the updated load forecasts filed by Hydro One on March 31, 2022.

Table 7 and Table 8 summarize the resulting Transmission and Distribution load forecasts, highlighting the changes resulting from this Settlement Proposal.

**Table 7 - Transmission Load Forecast 2023-2027 (12-Month Average Peak in MW)[9]**

| Year | Ontario Demand | | Hydro One Rate Categories (Charge Determinants) | | | | | |
|---|---|---|---|---|---|---|---|---|
| | | | Network | | Line Connection | | Transformation Connection | |
| | Proposed Transmission Load Forecast | Settled Transmission Load Forecast | Proposed Transmission Load Forecast | Settled Transmission Load Forecast | Proposed Transmission Load Forecast | Settled Transmission Load Forecast | Proposed Transmission Load Forecast | Settled Transmission Load Forecast |
| 2023 | 19,416 | 19,600 | 19,218 | 19,399 | 18,655 | 18,830 | 15,869 | 16,018 |
| 2024 | 19,414 | 19,650 | 19,215 | 19,449 | 18,653 | 18,879 | 15,868 | 16,059 |
| 2025 | 19,303 | 19,402 | 19,106 | 19,204 | 18,548 | 18,642 | 15,778 | 15,858 |
| 2026 | 19,191 | 19,321 | 18,995 | 19,124 | 18,441 | 18,565 | 15,687 | 15,792 |
| 2027 | 19,238 | 19,392 | 19,042 | 19,194 | 18,486 | 18,633 | 15,725 | 15,850 |

**Table 8 - Distribution Load[10] and Customer Forecast 2023-2027[11]**

| Year | GWh Delivered Forecast | | Distribution Customer Count |
|---|---|---|---|
| | March 2022 Update | Settlement | |
| 2023 | 35,522 | 35,902 | 1,413,905 |
| 2024 | 35,497 | 35,998 | 1,424,106 |
| 2025 | 35,400 | 35,608 | 1,434,135 |
| 2026 | 35,273 | 35,540 | 1,443,532 |
| 2027 | 35,379 | 35,701 | 1,452,813 |

As part of the load forecast calculations, Hydro One made certain assumptions about historical CDM amounts which were not accepted in whole and the load forecast presented in the current settlement proposal has been adjusted accordingly. Due to the time needed to reflect the agreed-upon load forecast in rates and bill impacts, Hydro One will update the final charge determinants by rate class, consistent with the overall load shown in Table 8 and consistent with the methodologies outlined in Exhibit D-5-1 for distribution, at the same time it updates Attachments 1 and 2 to incorporate the OEB's 2023 Cost of Capital parameters and Inflation Factors for 2023 which will be filed with the OEB by mid-November. Similarly, Hydro One will update the calculations of the Uniform Transmission rates, associated transmission-related bill impacts and any related Attachments to reflect the agreed-upon transmission

[9] See Exhibit O-01-03, Table 1 for proposed amounts.

[10] Values in Table 8 represent delivery at the wholesale level and will not match those used for purposes of cost allocation and rate design, which reflect consumption at customer meter level.

[11] See Exhibit O-01-03, Table 6 for March 2022 Update amounts and Exhibit D-05-01, Table 3 for distribution customer count.

charge determinants shown in Table 7 above and to incorporate the OEB's 2023 Cost of Capital parameters and Inflation Factors for 2023 which will be filed with the OEB by mid-November.

Table Table 9 - 9 and Table 10 summarize the bill impacts of the Application to a typical R1 (without DRP) and GSe customer, updated to reflect the terms of this Settlement Proposal. Three bill impacts are presented: (i) as-filed bill impacts;[12] (ii) bill impacts arising from Hydro One's March 31, 2022 Evidence Update, but without deferral of the incremental approved revenue requirement amounts arising from Hydro One's updated inflation assumptions and the revenue deficiency arising from updates made to the CDM assumptions in Hydro One's load forecasts, as presented in O-PP-022 and O-SEC-252;[13] and (iii) bill impacts arising as a result of the terms of this Settlement Proposal. Throughout this document, bill impacts arising from this Settlement Proposal are provided relative to the bill impacts presented in O-PP-022 and O-SEC-252.

[12] See Exhibits H-10-01 and L-06-01.

[13] The March 31, 2022 Evidence Update included a proposal (ultimately rejected in this Settlement Proposal) to defer the incremental revenue requirement arising from the load and inflation updates to the future rate period. Bill impacts resulting from the load and inflation and updates were provided in I-18-O-PP-022 and I-22-O-SEC-252.

**Table 9 - Combined Bill Impacts of Changes in Transmission and Distribution Revenue Requirements and Disposition of Deferral and Variance Account Balances**

| Rate Class | Monthly Consumption (kWh) | | 2023 | | | 2024 | | | 2025 | | | 2026 | | | 2027 | | | 5-year average | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | Change in Total Bill ($) - Prefiled | Change in Total Bill ($) – March 2022 | Change in Total Bill ($) - As settled | Change in Total Bill ($) - Prefiled | Change in Total Bill ($) – March 2022 | Change in Total Bill ($) - As settled | Change in Total Bill ($) - Prefiled | Change in Total Bill ($) – March 2022 | Change in Total Bill ($) - As settled | Change in Total Bill ($) - Prefiled | Change in Total Bill ($) – March 2022 | Change in Total Bill ($) - As settled | Change in Total Bill ($) - Prefiled | Change in Total Bill ($) – March 2022 | Change in Total Bill ($) - As settled | Change in Total Bill ($) - Prefiled | Change in Total Bill ($) – March 2022 | Change in Total Bill ($) - As settled |
| **R1 (without DRP)** | 750 | **DX Impact** | ($2.78) | ($1.46) | ($1.37) | $1.40 | $1.56 | $1.04 | $2.36 | $2.64 | $2.09 | $3.18 | $2.95 | $3.54 | $2.26 | $2.91 | $2.28 | $1.29 | $1.72 | $1.52 |
| | | **TX Impact** | ($0.43) | ($0.30) | ($0.49) | $0.49 | $0.82 | $0.65 | $0.61 | $0.80 | $0.78 | $0.77 | $1.00 | $0.78 | $0.52 | $0.59 | $0.47 | $0.39 | $0.58 | $0.44 |
| | | **Combined Impact** | ($3.20) | ($1.76) | ($1.86) | $1.89 | $2.38 | $1.69 | $2.97 | $3.44 | $2.87 | $3.95 | $3.95 | $4.32 | $2.78 | $3.50 | $2.74 | $1.68 | $2.30 | $1.95 |
| **GSe** | 2,000 | **DX Impact** | ($8.32) | ($5.76) | ($5.62) | $1.43 | $2.18 | $1.03 | $6.12 | $6.98 | $5.65 | $8.38 | $9.25 | $9.41 | $6.99 | $7.79 | $6.21 | $2.92 | $4.09 | $3.33 |
| | | **TX Impact** | ($0.90) | ($0.64) | ($1.04) | $1.03 | $1.74 | $1.38 | $1.30 | $1.70 | $1.65 | $1.62 | $2.12 | $1.65 | $1.11 | $1.26 | $0.99 | $0.83 | $1.24 | $0.93 |
| | | **Combined Impact** | ($9.22) | ($6.40) | ($6.66) | $2.46 | $3.92 | $2.40 | $7.42 | $8.68 | $7.30 | $10.00 | $11.37 | $11.06 | $8.10 | $9.05 | $7.20 | $3.75 | $5.33 | $4.26 |

*Total bill impact includes DVA dispositions, Ontario Electricity Rebate and Taxes*

**Table 10 - Combined Bill Impacts of Changes in Transmission and Distribution Revenue Requirements and Disposition of Deferral and Variance Account Balances**

| Rate Class | Monthly Consumption (kWh) | | 2023 | | | 2024 | | | 2025 | | | 2026 | | | 2027 | | | 5-year average | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | Change in Total Bill (%) - Prefiled | Change in Total Bill (%) – March 2022 | Change in Total Bill (%) - As settled | Change in Total Bill (%) - Prefiled | Change in Total Bill (%) – March 2022 | Change in Total Bill (%) – As settled | Change in Total Bill (%) - Prefiled | Change in Total Bill (%) – March 2022 | Change in Total Bill (%) - As settled | Change in Total Bill (%) - Prefiled | Change in Total Bill (%) – March 2022 | Change in Total Bill (%) - As settled | Change in Total Bill (%) - Prefiled | Change in Total Bill (%) – March 2022 | Change in Total Bill (%) - As settled | Change in Total Bill (%) - Prefile d | Change in Total Bill (%) – March 2022 | Change in Total Bill (%) - As settled |
| R1 (without DRP) | 750 | **DX Impact** | -1.8% | -0.9% | -0.9% | 0.9% | 1.0% | 0.7% | 1.5% | 1.7% | 1.3% | 2.0% | 1.8% | 2.2% | 1.4% | 1.8% | 1.4% | 0.8% | 1.1% | 1.0% |
| | | **TX Impact** | -0.3% | -0.2% | -0.4% | 0.4% | 0.6% | 0.5% | 0.5% | 0.6% | 0.6% | 0.6% | 0.8% | 0.6% | 0.4% | 0.4% | 0.3% | 0.3% | 0.4% | 0.3% |
| | | **Combined Impact** | -2.1% | -1.2% | -1.2% | 1.3% | 1.6% | 1.2% | 2.0% | 2.3% | 1.9% | 2.6% | 2.6% | 2.8% | 1.8% | 2.2% | 1.8% | 1.1% | 1.5% | 1.3% |
| GSe | 2,000 | **DX Impact** | -2.0% | -1.4% | -1.3% | 0.4% | 0.5% | 0.2% | 1.5% | 1.7% | 1.4% | 2.0% | 2.2% | 2.3% | 1.7% | 1.8% | 1.5% | 0.7% | 1.0% | 0.8% |
| | | **TX Impact** | -0.2% | -0.2% | -0.2% | 0.3% | 0.4% | 0.3% | 0.3% | 0.4% | 0.4% | 0.4% | 0.5% | 0.4% | 0.3% | 0.3% | 0.2% | 0.2% | 0.3% | 0.2% |
| | | **Combined Impact** | -2.2% | -1.5% | -1.6% | 0.7% | 0.9% | 0.6% | 1.8% | 2.1% | 1.8% | 2.4% | 2.7% | 2.6% | 2.0% | 2.1% | 1.7% | 0.9% | 1.3% | 1.0% |

*Total bill impact includes DVA dispositions, Ontario Electricity Rebate and Taxes*

Tables 9 and 10 above are provided in Attachment 2, Schedule 7.3. A table that shows the year-over-year changes in charges for base distribution rates under each of the three scenarios noted in the paragraph above is also provided in Attachment 2, Schedule 7.4.

Note that the rates and bill impacts will be updated by mid-November to reflect: (i) OEB's 2023 Cost of Capital parameters and Inflation Factors for 2023; (ii) the Overhead Capitalization Adjustment (as defined and described below); and (iii) the load forecast included in Tables 7 and 8, above.

On a combined basis for Transmission and Distribution, as a result of the changes to the 2023 revenue requirement and load forecasts agreed to by the Parties in this Settlement Proposal, the estimated total monthly bill impact for a typical Hydro One medium density (R1) residential customer (750 kWh/month) will be a reduction of $1.86 in 2023, which is an additional $0.10 reduction relative to the bill impacts in the March 31, 2022 Evidence Update (without deferral). Moreover, as a result of the changes to the 2023-2027 capital-related revenue requirements and load forecasts agreed to by the Parties in this Settlement Proposal the average monthly bill impact over 2023-2027 will be an increase of $1.95 in each year of the rate period, which is a $0.35 reduction relative to the bill impacts in the March 31, 2022 Evidence Update (without deferral). On a combined basis for Transmission and Distribution, as a result of the changes to the 2023 revenue requirement and load forecasts agreed to by the Parties in this Settlement Proposal, the estimated total monthly bill impact for a typical Hydro One GSe<50kW customer (2,000 kWh/month) will be a reduction of $6.66 in 2023, which is an additional $0.26 reduction relative to the bill impacts in the March 31, 2022 Evidence Update (without deferral). Finally, as a result of the changes to the 2023-2027 capital-related revenue requirements and load forecasts agreed to by the Parties in this Settlement Proposal the average monthly bill impact over 2023-2027 will be an increase of $4.26 in each year of the rate period, which is a $1.07 reduction relative to the bill impacts in the March 31, 2022 Evidence Update (without deferral).

The Parties agree that: (i) the 2023 to 2027 cost of common equity for Transmission and Distribution will be based on the 2023 return on equity ("**ROE**") to be established by the OEB as part of the Cost of Capital Parameters to be published in the fourth quarter of 2022; (ii) the 2023 to 2027 cost of short-term debt for Transmission and Distribution will be based on the 2023 short-term debt rate to be established by the OEB as part of the Cost of Capital Parameters to be published in the fourth quarter of 2022; and (iii) the 2023 to 2027 cost of long-term debt for Transmission and Distribution will be based on Hydro One's actual 2021 and 2022 debt issuances, as well as forecasted debt issuances in 2022 and 2023 with coupon rates based on the 2022 September Consensus Forecast. The Parties have also agreed that, following the OEB's release of its 2023 Cost of Capital Parameters, Hydro One will update its long-term debt rates based on its actual 2021 and 2022 debt issuances, and the forecasted debt issues in 2022 and 2023 with coupon rates based on the September 2022 Consensus Forecast that may have changed since the filing of this Settlement Proposal and prior to the release of the 2023 Cost of Capital Parameters. As such, the numbers herein use the as-filed values for ROE, short-term debt and long-term debt.

The Parties acknowledge that some of the figures presented in this Settlement Proposal, in respect of Transmission, have been determined based on the assumption that the ETS Rate will remain at its existing level of $1.85/MWh, and that such rate is currently under consideration by the OEB in a generic proceeding (EB-2021-0243). Accordingly, certain figures set forth in this Settlement Proposal in respect of Transmission, which rely on the existing ETS Rate, may need to be updated if the OEB issues a decision in the generic proceeding modifying this rate effective from January 1, 2023.

The Parties also acknowledge that the Inflation Factor (I) for each of Transmission and Distribution will be updated annually to reflect the OEB-issued inflation factors. As part of the Custom IR Frameworks, the revenue requirements in 2024-2027 will be impacted by the updated Inflation Factors in future years. The figures in this Settlement Proposal for revenue requirements from 2024 to 2027 are presented based on the 2021 placeholder Inflation Factors set by the OEB consistent with the March 31, 2022 submission. These figures will be updated when the OEB issues the 2023 Inflation Factors consistent with the timing of Cost of Capital Parameters discussed above.

This Settlement Proposal is the culmination of extensive discussion and consideration by the Parties, which represent an array of interests affected by the Application. Based on the impacts of the settlement described above and in Part B below, together with the evidence and rationale provided and referenced in Part C below, the Parties agree that this Settlement Proposal is in the public interest and the Parties recommend its acceptance by the OEB.

Hydro One has prepared Supporting Schedules reflecting the terms of this Settlement Proposal and has included them at **Attachments 1, 2 and 3**. The Parties agree that the Supporting Schedules appropriately reflect the terms of this Settlement Proposal and recommend that, concurrent with its acceptance of the Settlement Proposal, the OEB approve the Supporting Schedules on a final basis subject to the updates for 2023 Cost of Capital Parameters, OEB Inflation Factors and, potentially, the ETS rate, as discussed above.

## B. KEY COMPONENTS OF SETTLEMENT

This section summarizes the key components of the settlement reached by the Parties. The evidentiary basis upon which each specific issue has been settled is summarized in Part C, below.

Relative to the proposed revenue requirement as of March 31, 2022, the settled revenue requirements for 2023 as shown in Table 11 and Table 12 below capture, among other things, the agreed upon capital and OM&A reductions for this Application as well as the associated in-service addition ("**ISAs**" or "**ISA**") impact. Each subsequent year's Transmission and Distribution revenue requirements (from 2024 to 2027) will be escalated based on the Custom IR Frameworks. Furthermore, at the time of the respective annual rate updates, the Inflation Factor (I) will be updated annually to reflect OEB issued factors for transmitters and distributors and the Capital Factor (C) consequently will be recalculated to align with the updated Inflation Factor (I) as further described in Part B, Section 1 below.

**Table 11 - 2023 Settled Transmission Revenue Requirement ($M)[14]**

| | 2023 |
|---|---|
| **Proposed Transmission Revenue Requirement** | **1,849.3** |
| OM&A | 442.6 |
| Environmental Provision addback to OM&A | 7.6 |
| Depreciation and Amortization | 539.5 |
| Environmental Provision reduction to Amortization Expense | (7.6) |
| Regulatory Taxes | 39.8 |
| Return on Capital | 827.4 |
| **Settled Transmission Revenue Requirement** | **1,831.9** |
| OM&A | 433.7 |
| Environmental Provision addback to OM&A | N/A |
| Depreciation and Amortization | 531.3 |
| Environmental Provision reduction to Amortization Expense | N/A |
| Regulatory Taxes | 43.8 |
| Return on Capital | 823.0 |
| **Difference** | **(17.4)** |

**Table 12 - 2023 Settled Distribution Revenue Requirement ($M)[15]**

| | 2023 |
|---|---|
| **Proposed Distribution Revenue Requirement** | **1,669.1** |
| OM&A | 628.9 |
| Environmental Provision addback to OM&A | 5.5 |
| Depreciation and Amortization | 470.6 |
| Environmental Provision reduction to Amortization Expense | (5.5) |
| Regulatory Taxes | 36.2 |
| Return on Capital | 533.4 |
| **Settled Distribution Revenue Requirement** | **1,654.6** |
| OM&A | 616.3 |
| Environmental Provision addback to OM&A | N/A |
| Depreciation and Amortization | 461.4 |
| Environmental Provision reduction to Amortization Expense | N/A |
| Regulatory Taxes | 39.8 |
| Return on Capital | 537.1 |
| **Difference** | **(14.5)** |

[14] The environmental provision add-back to OM&A costs and an offsetting Environmental Provision reduction to Depreciation and Amortization expense, as proposed by Hydro One in the 2023 rebasing year for both Transmission and Distribution, relates to the PCB Program.

[15] Ibid.

As part of the calculations of the revenue requirements for Transmission and Distribution based upon the agreed settlement parameters, overhead capitalization was updated to reflect the capital reductions impacting OM&A for each of Transmission and Distribution. As a result, the Transmission OM&A for 2023 included an additional $0.6M and the Distribution OM&A for 2023 included an additional $1.7M related to the recalculation of overhead capitalization ("**Overhead Capital Adjustment**"). The Overhead Capitalization Adjustment was not accepted and it has been removed from the revenue requirements presented in the current settlement proposal; however, because of the time needed to reflect this change in rates and bill impacts the Overhead Capitalization Adjustment continues to be shown in the ongoing calculation of revenue requirement, rates and bill impacts provided in Attachments 1 and 2. Hydro One will remove the Overhead Capitalization Adjustment from the revenue requirements used to calculate final rates and bill impacts when it updates the rates and bill impacts to incorporate the OEB's 2023 Cost of Capital parameters and Inflation Factors for 2023 which will be filed with the OEB by mid-November.

## 1. ***Plan Structure and Term***

For both the Transmission and Distribution businesses, the Parties agree to the overall structure of Hydro One's proposed Custom IR Frameworks, with 5-year test periods commencing January 1, 2023 and ending December 31, 2027, but with modifications to certain parameters of the frameworks.

Pursuant to the agreed-upon frameworks, the Transmission and Distribution revenue requirements for the first year of the period (2023) are determined using a cost of service, forward test year approach, and for each of the remaining years (2024-2027) are determined using the RCI approach in which the revenue requirement for the test year t+1 is equal to the revenue requirement in year t inflated by the RCI. The Custom RCI is expressed as RCI = I – X + C, where "I" is the Inflation Factor based on the OEB's two-factor input price index adopted for electricity transmitters and distributors, "X" is the Productivity Factor equal to the sum of Hydro One's custom Industry Total Factor Productivity measure and its custom stretch factor, and "C" is Hydro One's Custom Capital Factor, which is designed to recover incremental revenue each test year to support Hydro One's proposed system plans, but reduced by a Supplemental Stretch Factor on capital. The Custom IR Frameworks also include earnings sharing mechanisms ("**ESM**") and access to the OEB's Z-factor mechanism. As is discussed below, several of the parameters of the Custom RCI formula differ between transmission and distribution.

The modifications to the Transmission and Distribution Custom IR Frameworks arising from the proposed settlement are set out in Table 13 and Table 14, below (the modifications are shaded).

**Table 13 - Transmission Custom IR Framework**

| | Hydro One Proposal | Settlement Proposal |
|---|---|---|
| **Term** | 5 years | 5 years |
| **Overall Structure** | I – X + C | I – X + C |
| **Inflation Factor (I)** | Updated annually to reflect OEB issued factors for transmitters | Updated annually to reflect OEB issued factors for transmitters |
| **Productivity Factor (X)** | 0% | 0.15% |
| **Capital Factor (C)** | Updated annually for OEB inflation | Updated annually for OEB inflation |
| **Supplemental Stretch on Capital** | 0.15% | 0.20% |
| **ESM** | 100 bps deadband<br>50/50 sharing<br>Disposition of available balances in the next rebasing | 100 bps deadband<br>50/50 sharing<br>Disposition of 2021 to 2024 balances in annual update for 2026 rates |
| **Capital In-Service Variance Account (CISVA)** | Proposed | Agreed to not establish |
| **Z-Factor** | OEB-approved criteria | OEB-approved criteria |

**Table 14 - Distribution Custom IR Framework**

| | Hydro One Proposal | Settlement Proposal |
|---|---|---|
| **Term** | 5 years | 5 years |
| **Overall Structure** | I – X + C | I – X + C |
| **Inflation Factor (I)** | Updated annually to reflect OEB issued factors for distributors | Updated annually to reflect OEB issued factors for distributors |
| **Productivity Factor (X)** | 0.30% | 0.45% |
| **Capital Factor (C)** | Updated annually for OEB inflation | Updated annually for OEB inflation |
| **Supplemental Stretch on Capital** | 0.15% | 0.20% |
| **ESM** | 100 bps deadband<br>50/50 sharing<br>Disposition of available balances in the next rebasing | 100 bps deadband<br>50/50 sharing<br>Disposition of 2021 to 2024 balances in annual update for 2026 rates |
| **Capital In-Service Variance Account (CISVA)** | Proposed | Agreed to not establish |
| **Z-Factor** | OEB-approved criteria | OEB-approved criteria |

With respect to the approved ESM, Parties agree that as part of 2026 annual update applications (to be filed in 2025) for each of Transmission and Distribution, Hydro One will bring forward any ESM balances for disposition for the years 2021 to 2024, to the extent that the ESM is triggered and there are balances required to be disposed of.

Furthermore, the Parties agree that, in connection with its next cost-based rate application, Hydro One will consider potential alternative approach(es) for establishing the revenue requirement and/or rates for the years following the base year, while meeting OEB Renewed Regulatory Framework ("**RRF**") objectives and striking an appropriate balance of risk between customers and the utility. If Hydro One applies for another Custom IR in its next cost-based rate application, it will provide evidence regarding potential alternative approach(es) that were considered and why they were rejected.

Table 15, Table 16, and Table 17 for Transmission and Table 18, Table 19, and Table 20 for Distribution provide the calculated RCI Factors and the associated revenue requirements. The Inflation Factors (which are currently placeholders) will be updated annually over 2024-2027 period to reflect the OEB issued factors applicable to those years. The C-factors will be updated annually to reflect any changes to Inflation Factors. Furthermore, the current Inflation Factors will be updated when the OEB issues the 2023 Inflation Factors, consistent with the timing of Cost of Capital Parameters discussed above.

**Table 15 - Summary of Settled Revenue Requirement Components for Hydro One Transmission ($M)**

| Line | | 2023 | 2024 | 2025 | 2026 | 2027 |
|---|---|---|---|---|---|---|
| 1 | Rate Base | 14,534.4 | 15,342.4 | 16,271.0 | 17,148.5 | 17,940.2 |
| 2 | Return on Debt | 338.1 | 356.9 | 378.5 | 398.9 | 417.4 |
| 3 | Return on Equity | 484.9 | 511.8 | 542.8 | 572.1 | 598.5 |
| 4 | Depreciation | 531.3 | 558.7 | 591.5 | 614.1 | 634.8 |
| 5 | Income Taxes | 43.8 | 74.2 | 65.6 | 84.4 | 86.3 |
| 6 | **Total Capital Related Revenue Requirement** | **1,398.1** | **1,501.7** | **1,578.4** | **1,669.6** | **1,736.9** |
| 7 | Less Working Capital Related Revenue Requirement | | 2.3 | 2.3 | 2.3 | 2.4 |
| 8 | **Total Capital Related Revenue Requirement (excluding working capital)** | **1,398.1** | **1,499.4** | **1,576.2** | **1,667.2** | **1,734.5** |
| 9 | Less Productivity Factor on Capital (0.15%+0.20%) | | (5.2) | (5.5) | (5.8) | (6.1) |
| 10 | Less Prior Year Productivity Factor on Capital | | | (5.2) | (10.8) | (16.6) |
| 11 | Less Removing Working Capital from Capital Factor | | (0.1) | (0.0) | (0.1) | (0.0) |
| 12 | **Total Capital Related Revenue Requirement (including working capital and Productivity)** | **1,398.1** | **1,496.3** | **1,567.6** | **1,652.9** | **1,714.2** |
| 13 | OM&A | 433.7 | 441.8 | 449.9 | 458.3 | 466.7 |
| 14 | **Total Revenue Requirement** | **1,831.9** | **1,938.1** | **2,017.6** | **2,111.2** | **2,180.9** |
| 15 | Increase in Capital Related Revenue Requirement | | 98.2 | 71.3 | 85.3 | 61.3 |
| 16 | Increase in Capital Related Revenue Requirement as a percentage of Previous Year Total Revenue Requirement | | 5.36% | 3.68% | 4.23% | 2.90% |
| 17 | Less Capital Related Revenue Requirement in I-X | | 1.41% | 1.43% | 1.44% | 1.45% |
| 18 | **Capital Factor** | | **3.95%** | **2.25%** | **2.79%** | **1.45%** |

**Table 16 - Transmission Custom Revenue Cap Index (RCI) by Component (%)**[16]

| Custom Revenue Cap Index by Component | 2024 | | 2025 | | 2026 | | 2027 | |
|---|---|---|---|---|---|---|---|---|
| | **Proposed** | **Settled** | **Proposed** | **Settled** | **Proposed** | **Settled** | **Proposed** | **Settled** |
| Inflation Factor (I) | 2.00 | 2.00 | 2.00 | 2.00 | 2.00 | 2.00 | 2.00 | 2.00 |
| Productivity Factor (X) | 0.00 | (0.15) | 0.00 | (0.15) | 0.00 | (0.15) | 0.00 | (0.15) |
| Capital Factor (C)* | 4.43 | 3.95 | 2.82 | 2.25 | 3.79 | 2.79 | 1.86 | 1.45 |
| **Custom Revenue Cap Index Total** | **6.43** | **5.80** | **4.82** | **4.10** | **5.79** | **4.64** | **3.86** | **3.30** |

** Includes a Supplemental Stretch on capital as part of the calculation. Proposed Supplemental Stretch of 0.15% and Settled Supplemental Stretch of 0.20%*

**Table 17 - Hydro One Transmission Revenue Requirement by Year**[17]

| Year | Formula - Proposed | Transmission Revenue Requirement Proposed ($M) | Formula – Settled | Transmission Revenue Requirement Settled ($M) | Difference ($M) |
|---|---|---|---|---|---|
| 2023 | Cost of Service | 1,849.3 | Cost of Service | 1,831.9 | **(17.4)** |
| 2024 | 2023 Revenue Requirement x 1.0643 | 1,968.2 | 2023 Revenue Requirement x 1.0580 | 1,938.1 | **(30.1)** |
| 2025 | 2024 Revenue Requirement x 1.0482 | 2,063.0 | 2024 Revenue Requirement x 1.0410 | 2,017.6 | **(45.5)** |
| 2026 | 2025 Revenue Requirement x 1.0579 | 2,182.5 | 2025 Revenue Requirement x 1.0464 | 2,111.2 | **(71.3)** |
| 2027 | 2026 Revenue Requirement x 1.0386 | 2,266.6 | 2026 Revenue Requirement x 1.0330 | 2,180.9 | **(85.7)** |

[16] The Inflation Factors (which are currently used as placeholders) will be updated annually over 2024-2027 period to reflect the OEB issued factors applicable to those years. The C-factor will be updated annually to reflect any changes to Inflation Factors. At the time of the Cost of Capital update, the Inflation Factor placeholders will be updated to reflect the 2023 OEB-issued Inflation Factor.

[17] 2024-2027 revenue requirements will be updated annually to reflect the OEB-issued Inflation Factors as part of the annual updates.

**Table 18 - Summary of Revenue Requirement Components for Hydro One Distribution ($M)**

| Line | | 2023 | 2024 | 2025 | 2026 | 2027 |
|---|---|---|---|---|---|---|
| 1 | Rate Base | 9,460.0 | 9,979.0 | 10,572.5 | 11,152.6 | 11,655.7 |
| 2 | Return on Debt | 221.5 | 233.6 | 247.5 | 261.1 | 272.9 |
| 3 | Return on Equity | 315.6 | 332.9 | 352.7 | 372.0 | 388.8 |
| 4 | Depreciation | 461.4 | 481.3 | 514.7 | 545.9 | 578.6 |
| 5 | Income Taxes | 39.8 | 59.3 | 47.6 | 64.0 | 72.1 |
| 6 | **Total Capital Related Revenue Requirement** | **1,038.3** | **1,107.1** | **1,162.5** | **1,243.0** | **1,312.3** |
| 7 | Less Working Capital Related Revenue Requirement | | 17.3 | 17.4 | 17.5 | 17.6 |
| 8 | **Total Capital Related Revenue Requirement (excluding working capital)** | **1,038.3** | **1,089.8** | **1,145.1** | **1,225.6** | **1,294.8** |
| 9 | Less Productivity Factor on Capital (0.45%+0.20%) | | (7.1) | (7.4) | (8.0) | (8.4) |
| 10 | Less Prior Year Productivity Factor on Capital | | | (7.1) | (14.5) | (22.5) |
| 11 | Less Removing Working Capital from Capital Factor | | 0.2 | 0.4 | 0.6 | 0.8 |
| 12 | **Total Capital Related Revenue Requirement (including working capital and Productivity)** | **1,038.3** | **1,100.2** | **1,148.4** | **1,221.2** | **1,282.3** |
| 13 | OM&A | 616.3 | 627.1 | 638.0 | 649.2 | 660.6 |
| 14 | **Total Revenue Requirement** | **1,654.6** | **1,727.3** | **1,786.5** | **1,870.4** | **1,942.8** |
| 15 | Increase in Capital Related Revenue Requirement | | 61.9 | 48.2 | 72.8 | 61.1 |
| 16 | Increase in Capital Related Revenue Requirement as a percentage of Previous Year Total Revenue Requirement | | 3.74% | 2.79% | 4.07% | 3.27% |
| 17 | Less Capital Related Revenue Requirement in I-X | | 1.10% | 1.11% | 1.12% | 1.14% |
| 18 | **Capital Factor** | | **2.65%** | **1.68%** | **2.95%** | **2.12%** |

**Table 19 - Distribution Custom Revenue Cap Index (RCI) by Component (%)**[18]

| Custom Revenue Cap Index by Component | 2024 | | 2025 | | 2026 | | 2027 | |
|---|---|---|---|---|---|---|---|---|
| | Proposed | Settled | Proposed | Settled | Proposed | Settled | Proposed | Settled |
| Inflation Factor (I) | 2.20 | 2.20 | 2.20 | 2.20 | 2.20 | 2.20 | 2.20 | 2.20 |
| Productivity Factor (X) | (0.30) | (0.45) | (0.30) | (0.45) | (0.30) | (0.45) | (0.30) | (0.45) |
| Capital Factor (C) * | 3.15 | 2.65 | 2.60 | 1.68 | 3.70 | 2.95 | 2.74 | 2.12 |
| **Custom Revenue Cap Index Total** | **5.05** | **4.40** | **4.50** | **3.43** | **5.60** | **4.70** | **4.64** | **3.87** |

** Includes a Supplemental Stretch on capital as part of the calculation. Proposed Supplemental Stretch of 0.15% and Settled Supplemental Stretch of 0.20%*

**Table 20 - Hydro One Distribution Revenue Requirement by Year**[19]

| Year | Formula - Proposed | Distribution Revenue Requirement Proposed ($M) | Formula – Settled | Distribution Revenue Requirement Settled ($M) | Difference ($M) |
|---|---|---|---|---|---|
| 2023 | Cost of Service | 1,669.1 | Cost of Service | 1,654.6 | **(14.5)** |
| 2024 | 2023 Revenue Requirement x 1.0505 | 1,753.3 | 2023 Revenue Requirement x 1.0440 | 1,727.3 | **(26.1)** |
| 2025 | 2024 Revenue Requirement x 1.0450 | 1,832.2 | 2024 Revenue Requirement x 1.0343 | 1,786.5 | **(45.8)** |
| 2026 | 2025 Revenue Requirement x 1.0560 | 1,934.8 | 2025 Revenue Requirement x 1.0470 | 1,870.4 | **(64.5)** |
| 2027 | 2026 Revenue Requirement x 1.0464 | 2,024.6 | 2026 Revenue Requirement x 1.0387 | 1,942.8 | **(81.8)** |

[18] The Inflation Factors (which are currently used as placeholders) will be updated annually over 2024-2027 period to reflect the OEB issued factors applicable to those years. The C-factor will be updated annually to reflect any changes to Inflation Factors. At the time of the Cost of Capital update, the Inflation Factor placeholders will be updated to reflect the 2023 OEB-issued Inflation Factor.

[19] 2024-2027 revenue requirements will be updated annually to reflect the OEB-issued Inflation Factors as part of the annual updates.

**2. *Inflation Assumptions, Load Forecast Updates and Deferred Recovery Mechanism***

On March 31, 2022, Hydro One filed an evidence update to reflect the impact of inflation on its Investment Plans for Transmission and Distribution. The evidence update replaced the 2.0% Ontario CPI assumptions for Transmission and Distribution with actual Ontario CPI of 3.5% for 2021 and forecast Ontario CPI of 4.5% and 3.3% for 2022 and 2023, respectively, as provided by Scotiabank Capital, resulting in planned OM&A costs in 2023 and capital costs for 2023 to 2027 increasing by a proration factor of 1.0525 from as-filed amounts, with the expectation of inflation returning to normal levels over the 2024-2027 rate period and maintaining 2.0% Ontario CPI assumptions for 2024-2027.[20] Hydro One proposed to further update its inflation assumptions for 2022 and 2023 at the time of the DRO to reflect the most recent inflation actuals and forecast then available to a cap of 10% cumulative inflation over 2022 and 2023.[21]

As part of the same evidence update, Hydro One made modifications to the CDM assumptions in its load forecasts to reflect the materially higher CDM levels forecasted by the Independent Electricity System Operator ("**IESO**") in its 2021 Annual Planning Outlook ("**APO**") as compared to the IESO's 2020 APO upon which the CDM assumptions in Hydro One's load forecasts were initially based.

Additionally, Hydro One proposed as part of the evidence update to defer recovery of the incremental impacts of the inflation update and the shortfall in revenue requirement due to updates made to the CDM assumptions in its load forecasts to the next rate period.

The Parties have agreed that there will be no further updates to reflect updates to inflation for 2022 and 2023, including as part of the DRO. The Parties have also agreed that Hydro One's load forecasts will be as presented in its March 31, 2022 Evidence Update subject to the modifications described in Part B, Section 8 below. Furthermore, the Parties have agreed that Hydro One will not defer recovery of any incremental amounts as proposed in its March 31, 2022 Evidence Update.

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[20] As defined by Hydro One in Exhibit O-01-02, page 9, lines 1 to 13, the proration factor represents the relative increase from as-filed OM&A costs in 2023 and capital costs for 2023 to 2027 presented in the March 31, 2022 update. This factor was derived as follows:

$$Proration\ Factor = \frac{(1+\ i_{2021}) \times (1+\ i_{2022}) \times (1+\ i_{2023})}{(1+i_{as-filed})^3}$$

Where: $i_{2021}$ is the actual Ontario inflation in 2021 of 3.5%
$i_{2022}$ is the Scotia forecasted Ontario inflation in 2022 of 4.5%
$i_{2023}$ is the Scotia forecasted Ontario inflation in 2023 of 3.3%
$i_{as\text{-}filed}$ is the 2% rate used in as-filed plan

$$Proration\ Factor = \frac{(1.035)\text{x}(1.045)\text{x}(1.033)}{1.02^3} = 1.0525$$

[21] 10% cumulative inflation means the sum of inflation in 2022 and 2023 equals 10%.

## 3. *Rate Base and Capital – Transmission*

Establishing 2023 Rate Base

The Parties agree that Hydro One's 2023 opening net fixed assets for Transmission, used to establish 2023 rate base, will reflect 2021 actuals filed on April 8, 2022 and the forecast 2022 ISAs as filed on March 31, 2022. The 2023-2027 rate base amounts are set out in Table 21 below.

**Table 21 - 2023-2027 Settled Transmission Rate Base ($M)**

| | 2023 | 2024 | 2025 | 2026 | 2027 |
|---|---|---|---|---|---|
| **Proposed Transmission Rate Base**[22] | 14,611.5 | 15,516.6 | 16,585.5 | 17,602.6 | 18,534.1 |
| **Settled Transmission Rate Base** | 14,534.4 | 15,342.4 | 16,271.0 | 17,148.5 | 17,940.2 |
| **Difference** | **(77.1)** | **(174.2)** | **(314.5)** | **(454.1)** | **(594.0)** |

Capital and ISAs

Subject to the modifications to the capital expenditures set out in this Proposal, the Parties agree that Hydro One's total Transmission capital expenditures will be (i) unchanged for the System Access and System Service categories, (ii) reduced by 11% ($717.7M) for the System Renewal category, and (iii) reduced by 7% ($44.6M) for the General Plant category.[23] The Parties also agree that Progressive Productivity[24] will be held constant at $64.2M per year, as proposed. The agreed-upon reductions, represent an overall Transmission capital expenditure envelope reduction of 10% ($762.4M) over the five-year Custom IR term, relative to Hydro One's proposed Transmission capital expenditures, as shown in Table 22 - 22 below.

[22] Exhibit O-01-02, Table 18 (Transmission Rate Base, 2023-2027) dated March 31, 2022.

[23] See Issue 15 for additional details on General Plant capital expenditures.

[24] Progressive productivity represents commitments made in the prior Transmission Application with respect to undefined productivity the Company would strive to achieve (i.e. additional productivity for which there were no identified initiatives) that will be sustained through the 2023-2027 test period in the current Application.

**Table 22 - 2023-2027 Settled Transmission Capital ($M)**

| | 2023 | 2024 | 2025 | 2026 | 2027 | Total |
|---|---|---|---|---|---|---|
| **Proposed Transmission Capital[25]** | **1,509.3** | **1,540.7** | **1,526.6** | **1,538.5** | **1,524.3** | **7,639.4** |
| System Access | 83.6 | 74.6 | 63.0 | 38.4 | 52.8 | 312.3 |
| System Renewal | 1,239.8 | 1,292.8 | 1,317.3 | 1,344.4 | 1,330.4 | 6,524.6 |
| System Service | 95.6 | 107.0 | 90.3 | 98.0 | 94.8 | 485.7 |
| General Plant | 154.5 | 130.5 | 120.2 | 122.0 | 110.5 | 637.8 |
| Progressive Productivity | (64.2) | (64.2) | (64.2) | (64.2) | (64.2) | (321.0) |
| **Settled Transmission Capital** | **1,362.1** | **1,389.4** | **1,373.3** | **1,382.1** | **1,370.2** | **6,877.0** |
| System Access | 83.6 | 74.6 | 63.0 | 38.4 | 52.8 | 312.3 |
| System Renewal | 1,103.4 | 1,150.6 | 1,172.4 | 1,196.5 | 1,184.0 | 5,806.9 |
| System Service | 95.6 | 107.0 | 90.3 | 98.0 | 94.8 | 485.7 |
| General Plant | 143.7 | 121.4 | 111.8 | 113.4 | 102.8 | 593.1 |
| Progressive Productivity | (64.2) | (64.2) | (64.2) | (64.2) | (64.2) | (321.0) |
| **Difference** | **(147.2)** | **(151.3)** | **(153.3)** | **(156.4)** | **(154.1)** | **(762.4)** |
| System Access | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| System Renewal | (136.4) | (142.2) | (144.9) | (147.9) | (146.3) | (717.7) |
| System Service | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| General Plant | (10.8) | (9.1) | (8.4) | (8.5) | (7.7) | (44.6) |
| Progressive Productivity | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |

The total proposed Transmission ISAs of $7,624.5M over the five-year Custom IR term have been reduced by $669.4M as shown in Table 23 below, to reflect the impact of the capital reductions described above and have been updated on a basis that is consistent with Interrogatory C-SEC-175.[26]

[25] Exhibit O-01-02, Attachment 4A (Transmission Capital Expenditure Summary – OEB Appendix 2-AB) dated March 31, 2022.
[26] Interrogatory C-SEC-175 dated March 31, 2022

**Table 23 - 2023-2027 Settled Transmission In-Service Additions ($M)**

| | 2023 | 2024 | 2025 | 2026 | 2027 | Total |
|---|---|---|---|---|---|---|
| **Proposed Transmission ISA**[27] | **1,404.5** | **1,393.2** | **1,795.6** | **1,347.5** | **1,683.8** | **7,624.5** |
| System Access | 75.7 | 51.4 | 63.9 | 66.5 | 41.0 | 298.4 |
| System Renewal | 1157.6 | 1227.7 | 1488.5 | 1149.9 | 1476.5 | 6500.3 |
| System Service | 60.6 | 21.7 | 172.3 | 75.7 | 104.4 | 434.6 |
| General Plant | 166.8 | 156.6 | 135.1 | 119.6 | 126.1 | 704.2 |
| Progressive Productivity | (56.2) | (64.2) | (64.2) | (64.2) | (64.2) | (312.9) |
| **Settled Transmission ISA**[28] | **1,334.1** | **1,264.2** | **1,631.8** | **1,212.7** | **1,512.5** | **6,955.2** |
| *System Access* | 75.7 | 51.4 | 63.9 | 66.5 | 41.0 | 298.4 |
| System Renewal | 1,093.8 | 1,105.6 | 1,334.2 | 1,023.4 | 1,314.1 | 5,871.2 |
| System Service | 60.6 | 21.7 | 172.3 | 75.7 | 104.4 | 434.6 |
| General Plant | 160.1 | 149.6 | 125.7 | 111.2 | 117.3 | 663.9 |
| Progressive Productivity | (56.2) | (64.2) | (64.2) | (64.2) | (64.2) | (312.9) |
| **Difference** | **(70.5)** | **(129.0)** | **(163.8)** | **(134.9)** | **(171.2)** | **(669.4)** |
| System Access | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| System Renewal | (63.8) | (122.0) | (154.3) | (126.5) | (162.4) | (629.1) |
| System Service | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| General Plant | (6.6) | (7.0) | (9.5) | (8.4) | (8.8) | (40.3) |
| Progressive Productivity | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |

[27] Exhibit O-01-02, Attachment 4G (Transmission In-Service Additions – OEB Appendix 2-AB) dated March 31, 2022.
[28] The annual ISAs have been updated on basis that is consistent with Interrogatory C-SEC-175 dated March 31, 2022.

## 4. *Rate Base and Capital – Distribution*

Establishing 2023 Rate Base

The Parties agree that Hydro One's 2023 opening net fixed assets for Distribution, used to establish 2023 rate base, will reflect (i) incremental ISAs in both 2021 ($11.0M) and 2022 ($37.8M) arising from actual 2021 capital spending;[29] (ii) the forecast 2022 ISAs as filed on March 31, 2022; and (iii) $46.4M which represents 50% of the 2022 Storm Costs identified by Hydro One in updated JTU-2.23. The 2023-2027 rate base amounts are set out in Table 24 below.

**Table 24 - 2023-2027 Settled Distribution Rate Base ($M)**

| | 2023 | 2024 | 2025 | 2026 | 2027 |
|---|---|---|---|---|---|
| **Proposed Distribution Rate Base**[30] | 9,394.7 | 10,031.4 | 10,764.2 | 11,477.9 | 12,104.7 |
| **Settled Distribution Rate Base** | 9,460.0 | 9,979.0 | 10,572.5 | 11,152.6 | 11,655.7 |
| **Difference** | **65.4** | **(52.4)** | **(191.7)** | **(325.3)** | **(448.9)** |

Capex and ISAs

The Parties agree that, in recognition of the unique nature of the Advanced Metering Infrastructure ("**AMI**") 2.0 project and the need for it to be undertaken, there will be no reduction to capital expenditures for the AMI 2.0 project and that all referenced reductions to Distribution System Renewal capital expenditures will be applied excluding the expenditures related to AMI 2.0. The Parties also agree that the Distribution capital expenditures in relation to the AMI 2.0 project will be updated to reflect the latest information. Pursuant to the terms of the Settlement Proposal, AMI 2.0 project costs have been updated from the March 31st, 2022 filed amounts of $587.7M to $581M to reflect the most up-to-date cost estimate. The Parties also agree that Hydro One will establish a new AMI 2.0 Variance Account ("**AMIVA**"), consistent with the scope and terms for the account as proposed in Exhibit G-01-02, Attachment 8 (a copy of which is included in the Supporting Schedules, Attachment 3, Schedule 2.4) and as further articulated in Part C, Issue 29 below related to Deferral and Variance Accounts.

Subject to the modifications to the capital expenditures set out in this Proposal, the Parties agree that Hydro One's Distribution capital expenditures will be (i) unchanged for the System Access category, (ii) reduced by 21.7% ($390.2M) for the System Renewal category (after excluding AMI 2.0 related expenditures), (iii) reduced by 12% ($125.5M) for the System Service category, and (iv) reduced by 16.5% ($158.3M) for the General Plant category. The agreed-upon reductions represent an overall Distribution

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[29] The Parties agree that 2021 actual capital spending and associated ISAs will be included in rate base. Per Exhibit O-02-01, 2021 actual capital expenditures exceeded the forecast by $48.8M (Actuals of $762.8M vs. Forecast of $714.0M). 2021 actual ISAs exceeded the forecast by $11.0M (Actuals of $711.1M vs. Forecast of $700.1M) with the remaining $37.8M of ISAs associated with the 2021 capital spending coming into service in 2022 due to the multi-year nature of the work including station renewal, complex joint use and relocations and business enablement investments.

[30] Exhibit O-01-02, Table 19 (Distribution Rate Base, 2023-2027) dated March 31, 2022.

capital expenditure envelope reduction of 12.2% ($680.7M) over the five-year Custom IR term, relative to Hydro One's proposed Distribution capital expenditures, as shown in Table 25 below.

**Table 25 - 2023-2027 Settled Distribution Capital ($M)**

| | 2023 | 2024 | 2025 | 2026 | 2027 | Total |
|---|---|---|---|---|---|---|
| **Proposed Distribution Capital**[31] | **1,057.9** | **1,081.9** | **1,179.7** | **1,127.9** | **1,127.2** | **5,574.5** |
| System Access | 252.2 | 253.3 | 238.9 | 223.8 | 215.0 | 1,183.1 |
| System Renewal (Excluding AMI) | 360.1 | 366.6 | 358.4 | 354.8 | 358.4 | 1,798.3 |
| System Renewal (AMI Only)[32] | 32.5 | 65.3 | 161.7 | 162.6 | 165.5 | 587.7 |
| System Service | 206.8 | 178.6 | 241.6 | 202.1 | 216.7 | 1,045.9 |
| General Plant | 206.2 | 218.2 | 179.0 | 184.7 | 171.5 | 959.7 |
| **Settled Distribution Capital** | **920.8** | **949.2** | **1,040.0** | **992.5** | **991.3** | **4,893.8** |
| System Access | 252.2 | 253.3 | 238.9 | 223.8 | 215.0 | 1,183.1 |
| System Renewal (Excluding AMI)[33] | 282.0 | 287.0 | 280.6 | 277.8 | 280.6 | 1,408.0 |
| System Renewal (AMI Only) | 32.5 | 69.5 | 158.4 | 158.9 | 161.8 | 581.0 |
| System Service | 182.0 | 157.2 | 212.6 | 177.9 | 190.7 | 920.4 |
| General Plant | 172.2 | 182.2 | 149.5 | 154.2 | 143.2 | 801.3 |
| **Difference** | **(137.0)** | **(132.8)** | **(139.7)** | **(135.4)** | **(135.8)** | **(680.7)** |
| System Access | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| System Renewal (Excluding AMI) | (78.2) | (79.5) | (77.8) | (77.0) | (77.8) | (390.2) |
| System Renewal (AMI only) | 0.0 | 4.2 | (3.4) | (3.7) | (3.7) | (6.6) |
| System Service | (24.8) | (21.4) | (29.0) | (24.3) | (26.0) | (125.5) |
| General Plant | (34.0) | (36.0) | (29.5) | (30.5) | (28.3) | (158.3) |

The total proposed Distribution ISAs of $5,642.9M over the five-year Custom IR term have been reduced by $665.1M as shown in Table 26 below, to reflect the impact of the capital reductions described above and have been updated on a basis that is consistent with Interrogatory C-SEC-175.[34]

[31] Exhibit O-01-02, Attachment 4E (Distribution Capital Expenditure Summary – OEB Appendix 2-AB) dated March 31, 2022.
[32] Ibid.
[33] Updated per the terms of settlement to reflect the most up-to-date cost estimate.
[34] Interrogatory C-SEC-175 dated March 31, 2022.

**Table 26 - 2023-2027 Settled Distribution In-Service Additions (ISA) ($M)**

| | 2023 | 2024 | 2025 | 2026 | 2027 | Total |
|---|---|---|---|---|---|---|
| **Proposed Distribution ISA[35]** | **1,012.5** | **1,080.9** | **1,266.6** | **1,116.9** | **1,165.9** | **5,642.9** |
| *System Access* | 252.1 | 254.5 | 239.4 | 223.7 | 214.8 | 1,184.5 |
| *System Renewal (Excluding AMI)* | 340.4 | 382.6 | 369.2 | 338.7 | 368.4 | 1799.3 |
| *System Renewal (AMI Only)[36]* | 32.5 | 65.3 | 161.7 | 162.6 | 165.5 | 587.6 |
| *System Service* | 232.1 | 156.3 | 264.4 | 211.4 | 205.4 | 1,069.5 |
| *General Plant* | 155.5 | 222.2 | 231.9 | 180.5 | 211.8 | 1,001.9 |
| **Settled Distribution ISA** | **910.0** | **947.4** | **1,113.1** | **984.6** | **1,022.6** | **4,977.8** |
| System Access | 252.1 | 254.5 | 239.4 | 223.7 | 214.8 | 1,184.5 |
| System Renewal (Excluding AMI) | 270.6 | 299.6 | 289.1 | 265.2 | 288.4 | 1412.9 |
| System Renewal (AMI Only) | 32.4 | 69.5 | 158.4 | 158.9 | 161.8 | 581.0 |
| System Service | 218.1 | 138.3 | 232.6 | 186.0 | 180.7 | 955.7 |
| General Plant | 136.9 | 185.5 | 193.7 | 150.8 | 176.9 | 843.7 |
| **Difference** | **(102.5)** | **(133.5)** | **(153.5)** | **(132.3)** | **(143.3)** | **(665.1)** |
| System Access | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| System Renewal (Excluding AMI) | (69.9) | (83.0) | (80.1) | (73.5) | (80.0) | (386.5) |
| System Renewal (AMI only) | 0.0 | 4.2 | (3.4) | (3.7) | (3.7) | (6.6) |
| System Service | (14.0) | (18.1) | (31.7) | (25.4) | (24.6) | (113.8) |
| General Plant | (18.6) | (36.7) | (38.3) | (29.8) | (34.9) | (158.2) |

### 5. *Capital Structure and Cost of Capital*

Capital Structure

The Parties agree that Hydro One's Transmission and Distribution deemed capital structures for rate-making purposes will be 60% debt and 40% common equity. The 60% debt component will be comprised of 4% deemed short-term debt and 56% long-term debt. This capital structure is unchanged from the capital structures underlying Hydro One's current Transmission and Distribution rates and is consistent with the capital structure proposed in the Application and the OEB's Report on Cost of Capital (EB-2009-0084).

Cost of Capital

The Parties agree that the 2023 to 2027 cost of common equity for Transmission and Distribution will be based on the 2023 ROE to be established by the OEB as part of the Cost of Capital Parameters to be published in in the fourth quarter of 2022. The Parties acknowledge that their agreement on ROE in this Settlement Proposal does not preclude Hydro One or any of the Intervenors from making submissions to the OEB in relation to a process separate and apart from this Application and on a generic basis as to the appropriateness of applying the 2023 value for the ROE resulting from the OEB's currently approved cost of capital methodology in respect of ROE (EB-2009-0084).

[35] Exhibit O-01-02, Attachment 4H (Distribution In-Service Additions – OEB Appendix 2-AB) dated March 31, 2022.
[36] Updated per the terms of settlement to reflect the most up-to-date cost estimate

The Parties agree that the 2023 to 2027 cost of short-term debt for Transmission and Distribution will be based on the 2023 short-term debt rate to be published by the OEB as part of the Cost of Capital Parameters in the in the fourth quarter of 2022.

The Parties agree that the 2023 to 2027 cost of long-term debt for Transmission and Distribution will be based on Hydro One's actual 2021 and 2022 debt issuances, as well as forecasted debt issuances in 2022 and 2023 with coupon rates based on the 2022 September Consensus Forecast. The Parties have also agreed that, following the OEB's release of its 2023 Cost of Capital Parameters, Hydro One will also update its long-term debt rates based on its actual 2021 and 2022 debt issuances, and the forecasted debt issuances in 2022 and 2023 with coupon rates based on the September 2022 Consensus Forecast.

## 6. *OM&A – Transmission and Distribution*

For each of Transmission and Distribution, the Parties have agreed on a 2% reduction to the proposed OM&A envelopes, as shown in Table 27 and Table 28 below. The Parties further agreed that OM&A reductions would not be applied to Rights Payments.[37] The Parties also agreed that Hydro One will continue treating its PCB Program costs as part of Depreciation and Amortization when calculating its revenue requirement, and not as part of OM&A, as further explained in Part B, Section 7 below.

**Table 27 - 2023 Settled Transmission Total OM&A Expenses ($M)**

| | **2023** |
|---|---|
| **Proposed Transmission Total OM&A** | 442.6 |
| **Proposed Transmission Total OM&A (Including PCB Costs)[38]** | 450.2 |
| **Settled Transmission Total OM&A** | 433.7 |
| **Difference** | **(16.5)** |

[37] Rights Payments are covered in Exhibit E-09-04 (Taxes Other Than Income Taxes)

[38] Exhibit O-01-02, Table 6. 2023 OM&A in revenue requirement under the proposed PCB Treatment was $450.2M ($442.6M+$7.6M), where $7.6M represented the PCB costs for Transmission.

**Table 28 - 2023 Settled Distribution Total OM&A Expenses ($M)**

| | 2023 |
|---|---|
| **Proposed Distribution Total OM&A** | 628.9 |
| **Proposed Distribution Total OM&A (Including PCB Costs)[39]** | 634.4 |
| **Settled Distribution Total OM&A** | 616.3 |
| **Difference** | **(18.1)** |

**7. *Depreciation and Amortization***

Subject to one modification, the Parties agree that Hydro One's depreciation methodology and resulting depreciation expense (inclusive of amortization expense), for each of Transmission and Distribution over the plan term, will be as proposed, based on the Depreciation Study prepared by Alliance Consulting Group.[40] The Parties further agree that, with respect to Hydro One's amortization expense for each of Transmission and Distribution, Hydro One will continue treating its PCB Program costs as part of Depreciation and Amortization in revenue requirement and not as part of OM&A as proposed by Hydro One. Table 29 and Table 30 present the Depreciation and Amortization Expenses for each of Transmission and Distribution.

**Table 29 - 2023-2027 Settled Transmission Depreciation and Amortization Expenses ($M)**

| | 2023 | 2024 | 2025 | 2026 | 2027 |
|---|---|---|---|---|---|
| **Proposed Transmission Depreciation and Amortization Expense[41]** | 539.5 | 570.2 | 607.6 | 634.2 | 657.9 |
| **Proposed Transmission Depreciation and Amortization Expense (Excluding PCB Costs)[42]** | 531.9 | 562.7 | 601.0 | 634.2 | 657.9 |
| **Settled Transmission Depreciation and Amortization Expense** | 531.3 | 558.7 | 591.5 | 614.1 | 634.8 |
| **Difference** | **(0.6)** | **(4.0)** | **(9.5)** | **(20.1)** | **(23.2)** |

[39] Exhibit O-01-02, Table 7. 2023 OM&A in revenue requirement under the proposed PCB Treatment was $634.4M ($628.8M+$5.5M), where $5.5M represented the PCB costs for Distribution.
[40] Exhibit E-04-08, Attachment 1.
[41] Exhibit O-01-02 Table 22.
[42] Reflects the recovery of PCB costs under OM&A as originally proposed in the application to align with the revenue requirement calculations presented in Exhibits O-01-02 Attachments O5A-05E.

**Table 30 - 2023-2027 Settled Distribution Depreciation and Amortization Expenses ($M)**

| | 2023 | 2024 | 2025 | 2026 | 2027 |
|---|---|---|---|---|---|
| **Proposed Distribution Depreciation and Amortization Expense**[43] | 470.6 | 493.7 | 532.7 | 569.3 | 606.9 |
| **Proposed Distribution Depreciation and Amortization Expense (Excluding PCB Costs)**[44] | 465.1 | 488.2 | 531.7 | 569.3 | 606.9 |
| **Settled Distribution Depreciation and Amortization Expense** | 461.4 | 481.3 | 514.7 | 545.9 | 578.6 |
| **Difference** | **(3.7)** | **(6.9)** | **(17.0)** | **(23.5)** | **(28.4)** |

### 8. *Load Forecast – Transmission and Distribution*

The Parties agree that Hydro One will use the proposed methodologies to determine its Transmission and Distribution load forecasts with the modification to the load forecasts for each of Transmission and Distribution of reducing the assumptions for incremental achievable potential CDM by 100% for each of 2023 and 2024, and by 35% for each of the years from 2025-2027, relative to what was included in the updated load forecasts filed by Hydro One on March 31, 2022. The load forecasts resulting from this modification are presented in Table 7 and Table 8, above.

### 9. *Other Revenue – Transmission and Distribution*

The Parties agree that, subject to two modifications to External Revenues, Hydro One's proposed Other Revenues, for each of Transmission and Distribution, are appropriate. Table 31 and Table 32 present the agreed-upon Transmission and Distribution Other Revenue, respectively.

[43] Exhibit O-01-02 Table 23.
[44] Reflects the recovery of PCB costs under OM&A as originally proposed in the application to align with the revenue requirement calculations presented in Exhibits O-01-02 Attachments O5F-05J.

**Table 31 - 2023-2027 Settled Transmission Other Revenues ($M)**

| | 2023 | 2024 | 2025 | 2026 | 2027 |
|---|---|---|---|---|---|
| **Proposed Transmission Other Revenues[45]** | **87.4** | **54.7** | **54.4** | **53.1** | **53.5** |
| External Revenue | 40.1 | 36.2 | 36.5 | 36.2 | 37.3 |
| WMS Revenue[46] | 0.0 | 0.0 | - | - | - |
| Regulatory Assets | 26.4 | (1.1) | (1.1) | (1.1) | (1.1) |
| Export Revenues | 37.4 | 37.1 | 37.3 | 37.2 | 37.2 |
| Funding for LVSG Credit | (16.5) | (17.5) | (18.2) | (19.2) | (19.8) |
| **Settled Transmission Other Revenues** | **84.5** | **56.6** | **56.1** | **54.9** | **55.4** |
| External Revenue | 40.8 | 36.9 | 37.1 | 36.9 | 37.9 |
| WMS Revenue[46] | 0.0 | 0.0 | - | - | - |
| Regulatory Assets | 22.5 | - | - | - | - |
| Export Revenues[47] | 37.4 | 37.1 | 37.3 | 37.2 | 37.2 |
| Funding for LVSG Credit | (16.3) | (17.4) | (18.3) | (19.3) | (19.8) |
| **Difference** | **(2.9)** | **1.9** | **1.7** | **1.8** | **1.9** |

**Table 32 - 2023-2027 Settled Distribution Other Revenues ($M)**

| | 2023 | 2024 | 2025 | 2026 | 2027 |
|---|---|---|---|---|---|
| **Proposed Distribution Other Revenues[48]** | **46.4** | **46.5** | **46.5** | **46.0** | **46.1** |
| External Revenue | 46.4 | 46.5 | 46.5 | 46.0 | 46.1 |
| **Settled Distribution Other Revenues** | **43.6** | **43.9** | **44.1** | **43.8** | **44.2** |
| External Revenue | 43.6 | 43.9 | 44.1 | 43.8 | 44.2 |
| **Difference** | **(2.8)** | **(2.6)** | **(2.4)** | **(2.2)** | **(1.9)** |

[45] Interrogatory O-PP-022part d) dated May 16, 2022 and SC–DAY 1–Question A dated August 15, 2022: Other includes a refund of the $27.5M credit for External Revenue Variances to customers in 2023, and excludes the 2023 Deferred Tax Asset (DTA) amount (+$43.5M), approved in EB-2021-0185 on December 16, 2021.

[46] WMS Revenue for 2023 and 2024 is $0.03M and $0.02M respectively.

[47] As discussed in Part A, Section 5, Parties acknowledge that these revenues have been determined based on the assumption that the Export Transmission Service Rate will remain at its existing level of $1.85/MWh, and that such rate is currently under consideration by the OEB in a generic proceeding (EB-2021-0243).

[48] Exhibit O-01-02 Attachment 5F-5J (p. 3 and p. 5) dated March 31, 2022. Interrogatory O-PP-022 part d) dated May 16, 2022 and SC–DAY 1–Question A dated August 15, 2022 included Deferral and Variance Account balances however for Distribution these should be excluded as they are accounted for through rate riders. The Deferral and Variance Account balances were included as “Other” Revenue Requirement in Interrogatory O-PP-022 part d) to estimate total bill impact.

The Parties agree that, for External Revenues for each of Transmission and Distribution, Hydro One will increase the relevant amounts on a basis that is consistent with the inflationary increase that was applied to OM&A expenditures related to the associated External Revenues, namely Hydro One's Cost of Sales - External Work.[49] For Transmission, these updates represent an overall Transmission External Revenues envelope increase of 1.8% (or $3.4M) over the five-year Custom IR term, relative to Hydro One's proposed Transmission External Revenues, as shown in Table 33.

The Parties also agree that, for Distribution, Hydro One will update its External Revenues to reflect the pole attachment rate, currently $34.76 per attacher, per year, per pole, as determined by the OEB in EB-2021-0302. For Distribution, these updates represent an overall Distribution External Revenue envelope decrease of 5.1% or $12M over the five-year Custom IR term, relative to Hydro One's updated Distribution External Revenues. The Distribution External Revenues reflecting the new pole attachment charge are included as part of the responses to the Pre-Settlement questions, as noted in Appendix A.

Table 33 and Table 34 present the agreed-upon Transmission and Distribution External Revenues, respectively, which include the modifications described above.

**Table 33 - 2023-2027 Settled Transmission External Revenues ($M)**

| | 2023 | 2024 | 2025 | 2026 | 2027 |
|---|---|---|---|---|---|
| **Proposed Transmission External Revenues**[50] | **40.1** | **36.2** | **36.5** | **36.2** | **37.3** |
| Secondary Land Use | 28.0 | 24.3 | 24.6 | 24.9 | 25.1 |
| Station Maintenance | 3.4 | 3.4 | 3.4 | 3.2 | 3.2 |
| Engineering & Construction | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 |
| Other External Revenues | 8.4 | 8.2 | 8.1 | 7.8 | 8.6 |
| **Settled Transmission External Revenues** | **40.8** | **36.9** | **37.1** | **36.9** | **37.9** |
| Secondary Land Use | 28.0 | 24.3 | 24.6 | 24.9 | 25.1 |
| Station Maintenance | 3.6 | 3.6 | 3.6 | 3.4 | 3.4 |
| Engineering & Construction | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 |
| Other External Revenues | 8.8 | 8.6 | 8.5 | 8.2 | 9.1 |
| **Difference** | **0.7** | **0.7** | **0.6** | **0.7** | **0.7** |

*Note: Secondary Land Use remains unchanged. External Revenue related to the Cost of Sales - External Work (Station Maintenance, Engineering & Construction, and Other) has been increased on a basis that is consistent with the inflationary increase that was applied to Cost of Sales – External Work, as further described in the narrative above.*

[49] Exhibit E-04-06 for Transmission (Common Corporate Costs OM&A – Transmission Cost of Sales - External Work) and Exhibit E-04-07 for Distribution (Common Corporate Costs OM&A - Distribution Cost of Sales - External Work)

[50] Exhibit O-01-05, Table 2 (Updated Transmission External Revenues) dated March 31, 2022.

**Table 34 - 2023-2027 Settled Distribution External Revenues ($M)**

| | 2023 | 2024 | 2025 | 2026 | 2027 |
|---|---|---|---|---|---|
| **Proposed Distribution External Revenues[51]** | **46.4** | **46.5** | **46.5** | **46.0** | **46.1** |
| Retail Services Revenues - Regulated | 15.1 | 15.1 | 15.1 | 14.5 | 14.6 |
| Joint Use - Regulated[52] | 15.7 | 15.8 | 15.8 | 15.9 | 15.9 |
| Sentinel Lights - Regulated | 2.6 | 2.5 | 2.4 | 2.3 | 2.2 |
| Other External Work- Regulated | 3.5 | 3.6 | 3.6 | 3.7 | 3.7 |
| Distributor Generator Studies - Regulated | 0.5 | 0.5 | 0.5 | 0.5 | 0.5 |
| Joint Use - Unregulated | - | - | - | - | - |
| Other External Work – Unregulated | 3.8 | 3.8 | 3.8 | 3.8 | 3.8 |
| Storm Work Revenue - Unregulated | - | - | - | - | - |
| Standard Supply Service Charge | 4.2 | 4.3 | 4.3 | 4.3 | 4.4 |
| MicroFIT Revenues | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 |
| ST Local Transformation Charge | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 |
| **Settled Distribution External Revenues** | **43.6** | **43.9** | **44.1** | **43.8** | **44.2** |
| Retail Services Revenues - Regulated | 15.1 | 15.1 | 15.1 | 14.5 | 14.6 |
| Joint Use - Regulated | 12.5 | 12.7 | 13.0 | 13.3 | 13.6 |
| Sentinel Lights - Regulated | 2.6 | 2.5 | 2.4 | 2.3 | 2.2 |
| Other External Work- Regulated | 3.7 | 3.8 | 3.8 | 3.9 | 3.9 |
| Distributor Generator Studies - Regulated | 0.5 | 0.5 | 0.5 | 0.5 | 0.5 |
| Joint Use - Unregulated | - | - | - | - | - |
| Other External Work – Unregulated | 4.0 | 4.0 | 4.0 | 4.0 | 4.0 |
| Storm Work Revenue - Unregulated | - | - | - | - | - |
| Standard Supply Service Charge | 4.2 | 4.3 | 4.3 | 4.3 | 4.4 |
| MicroFIT Revenues | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 |
| ST Local Transformation Charge | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 |
| **Difference** | **(2.8)** | **(2.6)** | **(2.4)** | **(2.2)** | **(1.9)** |

## 10. *Deferral and Variance Accounts – Transmission*

Disposition

For Transmission, the Parties agree that Hydro One will dispose of its audited 2020 balances inclusive of projected carrying costs to December 31, 2022, adjusted for OEB approved dispositions in 2021 and 2022 (including a life-to-date credit adjustment to External Station Maintenance, E&CS and Other External Revenues variance account relating to the 2013 to 2020 years) totaling a credit balance of $22.5M to be returned to ratepayers, over a 1-year disposition period in 2023, rather than over a 5-year disposition period from 2023 to 2027 as originally proposed. The balance has been further adjusted to reflect the calculation of the Accelerated CCA Sub-Account based on actual additions as agreed by the Parties. The Transmission regulatory balances are provided in Table 35 below.

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[51] Exhibit D-02-02, Attachment 1 (Appendix 2H Other Operating Revenue) dated August 5, 2021.

[52] Joint Use – Regulated amounts reflect the revised pole attachment rate of $34.76 per attacher, per year, per pole, as determined by the OEB in EB-2021-0302.

**Table 35 - Transmission Regulatory Balances**[53]

| | | Principal as at December 31, 2022 | Interest as at December 31, 2022 | Total as at December 31, 2022 |
|---|---|---|---|---|
| 1508 | Long-Term Transmission Future Corridor Acquisition and Development Deferral Account | $0 | ($1,292) | ($1,292) |
| 1508 | LDC CDM and Demand Response Variance Account | $25,563,505 | $1,234,055 | $26,797,560 |
| 1508 | Waasigan Transmission Deferral Account – OM&A | $13,722 | $4,684 | $18,406 |
| 1508 | OPEB Cost Deferral Account | $28,541,944 | $912,328 | $29,454,272 |
| 1508 | Customer Connection and Cost Recovery Agreements (CCRA) True-Up Variance Account | $641,220 | $7,310 | $648,530 |
| 1522 | OPEB Asymmetrical Carrying Charge Account | ($1,024,277) | $0 | ($1,024,277) |
| 1592 | Tax Rate Changes Variance Account[1] | ($20,856,286) | ($752,603) | ($21,608,888) |
| 2405 | Excess Export Service Revenue Variance Account | $931,311 | $119,041 | $1,050,352 |
| 2405 | External Secondary Land Use Revenue Variance Account | ($16,270,000) | ($328,314) | ($16,598,314) |
| 2405 | External Station Maintenance, E&CS and Other External Revenue Variance Account | ($16,464,242) | ($1,586,674) | ($18,050,916) |
| 2405 | Rights Payments Variance Account | $897,108 | $38,192 | $935,301 |
| 2405 | Pension Costs Differential Variance Account | ($4,230,650) | ($276,157) | ($4,506,807) |
| 2405 | External Revenue – Partnership Transmission Projects Account Deferral Account | $0 | $1,875 | $1,875 |
| 2405 | Capital In-Service Variance Account | $0 | ($3,350) | ($3,350) |
| 2405 | Depreciation Expense (Asset Removal Costs) Asymmetrical Cumulative Variance Account | ($19,393,509) | ($231,469) | ($19,624,977) |
| **Total Regulatory Accounts Seeking Disposition** | | **($21,650,153)** | **($862,372)** | **($22,512,525)** |

*1: Transmission 1592 balance reflects clearance of 2018 and 2019 CCA Changes balances, updated in 2022 (on the Hydro One books) for actual additions method. In 2020 and onwards, the impact of accelerated CCA has been included in regulatory taxes already being collected in rates.*

[53] Exhibit G-01-01, Table 1 updated for External Station Maintenance, E&CS and Other External Revenues variance account in Exhibits O-01-05 and O-01-05-01 ($27.2M life-to-date credit adjustment) and further adjusted for calculation of the Accelerated CCA Sub-Account based on actual additions.

<u>Continuation and Discontinuation of Existing Accounts</u>
The Parties agree that Hydro One will continue or discontinue its existing Transmission deferral and variance accounts as proposed in the Application and as clarified during the proceeding (see Issue 28 in Part C below), subject to the following modifications:

a) Hydro One will discontinue the following three Transmission accounts:
    - the Waasigan Transmission Tracking Deferral Account;
    - the Transmission COVID-19 Emergency Deferral Account; and
    - the Transmission Capital In-Service Variance Account (CISVA).

<u>Establishment of New Accounts and Modifications to Existing Accounts</u>
The Parties agree that Hydro One will establish new Transmission regulatory accounts or modify existing Transmission regulatory accounts as proposed in the Application and as clarified during the proceeding (see Issue 29 in Part C below), subject to the following modifications:

b) Hydro One will establish the following two additional new Transmission accounts:
    - a Transmission Sale of Properties Deferral Account, which will include two sub-accounts: 1) A Revenue Requirement Impacts sub-account to record the revenue requirement impact, including taxes, associated with the rate base component of the sold land and buildings in the General Plant Facilities and Real Estate portfolio, which are being recovered in rates but no longer owned by Hydro One during all or part of the 2023-2027 Custom IR term. 2) A Gain/Loss on Sale sub-account to record the after-tax gains or losses from the sale of land and buildings in the General Plant Facilities and Real Estate portfolio recovered in rates, during the 2023-2027 Custom IR term. The prudence review will include amounts related to the sale price, gain/losses, and the impacts to rate base, including the timing of when the property is removed from rate base, not only amounts related to properties where impacts and gain/losses have been included in the account, but also if there are other properties that are no longer used or useful and that commercially reasonably could have been disposed of, but were not. A draft accounting order for the Transmission Sale of Properties Deferral Account is provided in Attachment 3, Schedule 1.4.

    - a Transmission Clean Energy Tax Credit Deferral Account to record the revenue requirement impacts of eligible new tax credits associated with investments in net-zero technologies, battery storage solutions and clean hydrogen that may be established by the Government of Canada, as contemplated at p. 94 of the 2022 Federal Budget issued on April 7, 2022 which would be disposed of in the next Transmission cost-based rate application. A draft accounting order for the Transmission Clean Energy Tax Credit Deferral Account is provided in Attachment 3, Schedule 1.5.

c) As the Parties agreed not to establish the deferred recovery mechanism as proposed by Hydro One in its evidence update, the related request for a “Transmission Approved Revenue Requirement Deferral Account” is no longer required.

d) As the Parties agreed that Hydro One will discontinue the Transmission CISVA, the proposed modification to the Transmission CISVA is no longer required.

## 11. *Deferral and Variance Accounts – Distribution*

Disposition

For Distribution, the Parties agree that Hydro One will dispose of its audited 2020 balances inclusive of projected carrying costs to December 31, 2022, adjusted for OEB approved dispositions in 2021, totaling a credit balance of $85.9M, not including the balances related to Account 1592, Sub-account CCA Changes for the former Norfolk Power Distribution Inc., Haldimand County Hydro Inc. and Woodstock Hydro Services Inc. (the "**Acquired Utilities**") to be returned to ratepayers, over a 3-year period from 2023 to 2025 rather than over a 5-year period from 2023 to 2027 as proposed by Hydro One in the Application, subject to the caveat that this modified disposition period may be adjusted with the further agreement of the Parties if necessary for purposes of rate mitigation. The balance has been adjusted to reflect the calculation of the Accelerated CCA Sub-Account based on actual additions as agreed by the parties. The Distribution Group 1 and Group 2 balances are provided below in Table 36.

**Table 36 - Distribution Group 1 and 2 Regulatory Balances[54]**

| | | Principal as at December 31, 2022 | Interest as at December 31, 2022 | Total Balance as at December 31, 2022 |
|---|---|---|---|---|
| 1550 | Low Voltage (LV) Variance Account | $2,025,886 | $56,243 | $2,082,129 |
| 1551 | Smart Meter Entity Charge Variance Account | ($146,637) | ($7,546) | ($154,183) |
| 1580 | RSVA - Wholesale Market Service Charge | (21,022,020) | (725,596) | (21,747,616) |
| 1580 | Variance WMS – Sub-account CBR Class | (3,126,683) | 141,877 | (2,984,806) |
| 1584 | RSVA - Retail Transmission Network Charge | ($14,640,666) | ($383,319) | ($15,023,985) |
| 1586 | RSVA - Retail Transmission Connection Charge | ($14,854,289) | $23,389 | ($14,830,900) |
| 1588 | RSVA - Power - Sub-Account -Power | ($2,946,661) | ($56,470) | ($3,003,132) |
| 1589 | RSVA - Power - Sub-Account -Global adjustment | ($13,470,859) | ($335,007) | ($13,805,866) |
| 1595 | Norfolk, 1595 (2018) residual balance | ($70,978) | 16,034 | ($54,944) |
| 1595 | Woodstock, 1595 (2018) residual balance | ($125,470) | $99,096 | ($26,374) |
| **Subtotal - Group 1 Accounts Requesting Disposition** | | **($68,378,378)** | **($1,171,298)** | **($69,549,677)** |
| 1508 | OEB Cost Differential Variance Account | ($2,305,407) | ($172,065) | ($2,477,472) |
| 1508 | Long Term Load Transfer (LTLT) Rate Impact Mitigation Deferral Account | $747,861 | $27,897 | $775,758 |
| 1508 | Bill Impact Mitigation Variance Account | ($1,292) | $6,330 | $5,039 |
| 1508 | OPEB Cost Deferral Variance Account | $67,160,292 | $1,916,763 | $69,077,055 |
| 1508 | Customer Choice Initiative Deferral Account | $845,288 | $10,438 | $855,727 |
| 1508 | Smart Grid Fund (SGF) Pilot Deferral Account | $2,186,198 | $146,346 | $2,332,544 |
| 1518/ 1548 | Retail Costs Variance Accounts (RCVA) | $769,314 | $80,196 | $849,510 |
| 1522 | OPEB Asymmetrical Carrying Charge Account | $0 | ($1,527,293) | ($1,527,293) |
| 1592 | Tax Rate Changes Variance Account[1] | ($45,905,603) | ($1,244,370) | ($47,149,972) |
| 2405 | Pension Cost Differential Variance Account | ($22,444,322) | ($1,504,860) | ($23,949,182) |
| 2435 | Earnings Sharing Mechanism (ESM) Deferral Account | ($14,920,514) | ($230,224) | ($15,150,738) |
| **Subtotal - Group 2 Accounts Requesting Disposition** | | ($13,868,184) | ($2,474,405) | ($16,359,025) |
| **Total Regulatory Accounts Requesting Disposition** | | **($82,246,562)** | **($3,662,139)** | **($85,908,701)** |

*1: Distribution 1592 balance reflects clearance of 2018 to 2020 CCA Changes balances, updated in 2022 (on the Hydro One books) for actual additions method.*

[54] Exhibit G-01-01, Table 2 adjusted for calculation of the Accelerated CCA Sub-Account based on actual additions.

Furthermore, in the OEB's Decision and Order on the Motion to Review and Vary for the Acquired Utilities (EB-2022-0071), the OEB directed Hydro One to calculate its Account 1592 entries for 2018-2022 using the Actual Additions Method with the resulting balances to be disposed of in the current proceeding (EB-2021-0110).[55] The OEB subsequently approved the balances for Account 1592, Sub-account CCA Changes, for each of the Acquired Utilities, on the basis that their disposition, along with carrying charges up to the effective date of disposition, would be addressed in the current Application.[56] The CCA balances of the Acquired Utilities to be returned to ratepayers is $1.3M as further presented under Section C, Issue 28 below. Parties agree to dispose of the balances over a 3-year period from 2023 to 2025 consistent with the Hydro One Distribution balances discussed above.

Continuation and Discontinuation of Existing Accounts

The Parties agree that Hydro One will continue or discontinue its existing Distribution deferral and variance accounts as proposed in the Application and as clarified during the proceeding (see Issue 28 in Part C below), subject to the following modifications:

a) Hydro One will discontinue the following two Distribution accounts:
    - the Distribution COVID-19 Emergency Deferral Account; and
    - the Distribution Capital In-Service Variance Account (CISVA).

Establishment of New Accounts and Modifications to Existing Accounts

The Parties agree that Hydro One will establish new Distribution regulatory accounts or modify existing Distribution regulatory accounts as proposed in the Application and as clarified during the proceeding (see Issue 29 in Part C below), subject to the following modifications:

b) Hydro One will establish the following four additional new Distribution accounts:
    - a Distribution Sale of Properties Deferral Account, which will include two sub-accounts: 1) A Revenue Requirement Impacts sub-account to record the revenue requirement impact, including taxes, associated with the rate base component of the sold land and buildings in the General Plant Facilities and Real Estate portfolio, which are being recovered in rates but no longer owned by Hydro One during all or part of the 2023-2027 Custom IR term. 2) A Gain/Loss on Sale sub-account to record the after-tax gains or losses from the sale of land and buildings in the General Plant Facilities and Real Estate portfolio recovered in rates, during the 2023-2027 Custom IR term. The prudence review will include amounts related to the sale price, gain/losses, and the impacts to rate base, including the timing of when the property is removed from rate base, not only amounts related to properties where impacts and gain/losses have been included in the account, but also if there are other properties that are no longer used or useful and that commercially reasonably could have been disposed of, but were not. A draft accounting order for the Distribution Sale of Properties Deferral Account is provided in Attachment 3, Schedule 2.6.

[55] EB-2022-0071, Decision and Order, April 7, 2022, pp. 6, 9 and 11.
[56] EB-2022-0071, Decision and Order, May 12, 2022, p. 2.

- a Distribution Clean Energy Tax Credit Deferral Account to record the revenue requirement impacts of eligible new tax credits associated with investments in net-zero technologies, battery storage solutions and clean hydrogen that may be established by the Government of Canada, as contemplated at p. 94 of the 2022 Federal Budget issued on April 7, 2022, which would be disposed of in the next Distribution cost-based rate application. A draft accounting order for the Distribution Clean Energy Tax Credit Deferral Account is provided in provided in Attachment 3 Schedule 2.7.

- Distribution System Energy Storage - Grid Scale Third-Party Accounting Treatment Variance Account to record the difference in the revenue requirement impact between Hydro One's current accounting treatment of the forecast costs as set out in the D-SS-04 for a grid scale energy storage project, and any alternative accounting treatment informed by any future OEB guidance pertaining to cost recovery for innovative solutions, if Hydro One enters into an arrangement with a third-party to provide reliability services. A draft accounting order for the Distribution System Energy Storage - Grid Scale Third-Party Accounting Treatment Variance Account is provided in Attachment 3, Schedule 2.8.

- Distribution System Energy Storage - Residential Deferral Account. Hydro One may procure the services of a third-party aggregator in respect of its residential battery storage units associated with the residential energy storage investments in D-SS-04. To the extent that these third-party units are used to participate in IESO markets and if such participation generates net revenues to the benefit of Hydro One, Hydro One will record the net revenue in the Residential Deferral Account, if any. A draft accounting order for the Distribution System Energy Storage - Residential Deferral Account is provided in Attachment 3, Schedule 2.9.

c) The Parties agree with Hydro One's proposal to establish a new Distribution Externally Driven Projects Variance Account, subject to a modified scope relative to that which was proposed and further articulated during the proceeding by Hydro One. The new account will capture variances as proposed in relation to Joint Use and Relocations (D-SA-01), as well as variances in relation to Customer Demand Distributed Energy Resource (DER) (D-SA-03) upgrades or DER connections, but only where triggered by specific IESO procurement initiatives. The new account will not capture variances in relation to New Load Connections, Upgrades and Cancellations (D-SA-02) as originally proposed. A draft accounting order for the Distribution Externally Driven Projects Variance Account is provided in Attachment 3, Schedule 2.2.

d) As the Parties agreed not to establish the deferred recovery mechanism as proposed by Hydro One in the evidence update, the related request for a "Distribution Approved Revenue Requirement Deferral Account" is no longer required.

**12.** ***Cost Allocation and Rate Design***

Transmission

The Parties agree with Hydro One's proposals for Transmission cost allocation and rate design, with no modifications.

Distribution

The Parties agree with Hydro One's proposals for Distribution cost allocation and rate design, subject to the modifications as described in Issue(s) 31, 32, 34 and 36 under Part C of this Settlement Proposal.

**13.** ***Implementation and Effective Date***

The Parties accept that the Transmission revenue requirement for the 2023 test year arising from this Settlement Proposal will be effective on January 1, 2023 and will be implemented as of that same date through an amendment to the Uniform Transmission Rates. Additionally, the Parties accept that the Distribution rates for the 2023 test year arising from this Settlement Proposal will also be effective and implemented on January 1, 2023.

The Parties further accept Hydro One's proposal that, in the event the requested rate orders cannot be implemented by January 1, 2023 to correspond to the agreed effective date of January 1, 2023, Hydro One's current transmission revenue requirement and charge determinants, and/or its current distribution rates and charges, will be effective on an interim basis as of January 1, 2023 and that Hydro One will recover any differences between the interim rates and the final rates effective January 1, 2023 in foregone revenue deferral accounts for Transmission and Distribution, as applicable.

**14.** ***Studies, Reports, Reporting and Other Matters***

The Parties agree that Hydro One will provide reporting, arrange for independent third-party studies to be undertaken, engage in planning processes, undertake line loss analysis and address specific program requirements and other matters, each as is more particularly described through the Settlement Proposal including **Appendix 'A'** hereto.

## C. SETTLEMENT BY ISSUE

The subsections below summarize the key components of the comprehensive settlement reached by the Parties, including details on how each of the issues in the Approved Issues List has been addressed either through the Application or through the modifications to Hydro One's proposals which have been agreed upon in this Settlement Proposal.

### 1.0 GENERAL

*1. Has Hydro One responded appropriately to all relevant Ontario Energy Board (OEB) directions from previous Transmission and Distribution rate proceedings?*

**Complete Settlement**

The Parties agree that Hydro One has responded appropriately to all relevant OEB directions from previous Transmission and Distribution rate proceedings.

**Approval**

| | |
|---|---|
| Parties in Support: | Anwaatin, AMPCO, CME, CCC, DRC, EP, LPMA, MFN, OSEA, PP, QMA, SEC, VECC |
| Parties Opposed: | None |
| Parties Taking No Position: | CUSW, SUP, ED, PWU, IRSS |

**Evidence**

The evidence in relation to this issue includes the following:

| | |
|---|---|
| Pre-filed Evidence | A-02-04 Summary of Board Directives and Undertakings from Previous Proceedings *(this exhibit lists each pre-filed evidence reference associated with each OEB directive from previous proceedings)* |
| Evidence Update | N/A |
| Interrogatories | I-01-E-Staff-203, I-01-E-Staff-265, I-02-B1-Anwaatin-002 |
| Undertakings | N/A |
| Pre-Settlement | N/A |
| Other | N/A |

2. *Are all elements of the proposed Transmission and Distribution revenue requirements and their associated total bill impacts reasonable?*

**Complete Settlement**

The Parties accept that (i) the impacts arising from Hydro One's proposals as modified by the terms of this Settlement Proposal[57] and (ii) the resulting Transmission and Distribution revenue requirements and associated total bill impacts are reasonable.

Attachments 1 and 2 to this Settlement Proposal attach Hydro One's Supporting Schedules for transmission and distribution respectively. Attachment 2, Schedule 7.0 and 7.1 for distribution sets out estimated rate and bill impacts for customers in each rate class. Attachment 1, Schedule 2.6 for transmission sets out average bill impacts on transmission and distribution-connected customers as well as bill impacts for a typical R1 residential customer and a General Service Energy customer consuming less than 50 kW. Moreover, tables 7 and 8 in Part A of this Settlement Proposal set out the combined bill impacts of changes in the transmission and distribution revenue requirements.

**Approval**

| | |
|---|---|
| Parties in Support: | Anwaatin, AMPCO, CME, CCC, DRC, EP, LPMA, MFN, OSEA, PP, QMA, SEC, VECC |
| Parties Opposed: | None |
| Parties Taking No Position: | CUSW, SUP, ED, PWU, IRSS |

**Evidence**

The evidence in relation to this issue includes the following:

| | |
|---|---|
| Pre-filed Evidence | D-01-01 Summary of Revenue Requirement (+ Att #1-10)<br>H-10-01 Transmission Bill Impacts<br>L-06-01 Distribution Bill impacts and Mitigation (+ Att #1-5) |
| Evidence Update | O-01-02 Inflation Update (+ Att #05A-05J) |
| Interrogatories | I-01-L-Staff-322, I-01-O-Staff-357, I-01-O-Staff-360, I-01-O-Staff-392, I-06-L-CCC-004, I-06-L-CCC-042, I-08-O-Energy Probe-083, I-14-A-LPMA-001, I-14-LPMA-029, I-14-LPMA-032, I-18-O-PP-022, I-21-L-RG-001 (+ Att #1) to RG-002, I-22-H-SEC-232, I-22-L-SEC-237 to SEC-238, I-22-O-SEC-246, I-22-O-SEC-252 to SEC-253, I-23-O-SUP-018, I-24-G-VECC-094, I-24-O-VECC-149, I-24-O-VECC-163, I-24-O-VECC-165, I-24-O-VECC-167, I-24-O-VECC-171 |

[57] Modifications include: changes to the capital expenditures and the associated ISAs and OM&A expenses (including PCB Program costs treatment) set out in this Proposal including the impact on 2023 opening rate base for each of Transmission and Distribution, as well as modifications to certain parameters to be used as part of the Custom IR Frameworks for calculating revenue requirements for 2024 to 2027.

| | |
|---|---|
| Undertakings | JTU-1.17, JTU-1.21, JT-4.10, JT-VECC-TCQ-26 |
| Pre-Settlement | SC-22-SEC-02, SC-22-SEC-06 |
| Other | SC Day 1 Responses – A |

*3. Were Hydro One's customer engagement activities sufficient to enable customer needs and preferences to be considered in the formulation of its proposed spending?*

**Complete Settlement**

In the context of the settled revenue requirement, the Parties accept Hydro One's evidence that its customer engagement activities were sufficient to enable customer needs and preferences to be considered in the formulation of its proposed spending.

**Approval**

| | |
|---|---|
| Parties in Support: | Anwaatin, AMPCO, CME, CCC, DRC, EP, LPMA, MFN, OSEA, PP, QMA, SEC, VECC |
| Parties Opposed: | None |
| Parties Taking No Position: | CUSW, SUP, ED, PWU, IRSS |

**Evidence**

The evidence in relation to this issue includes the following:

| | |
|---|---|
| Pre-filed Evidence | B-01-01 SPF Section 1.6 Customer Engagement (+ Att #1-7) |
| Evidence Update | O-01-01 Evidence Update – Executive Summary |
| Interrogatories | I-02-B1-Anwaatin-002, I-02-O-Anwaatin-007 to Anwaatin-008, I-04-B1-CME-007 to CME-008, I-07-B1-DRC-007, I-22-B1-SEC-048 (+ Att #20), I-22-B1-SEC-055 (+ Att #1) |
| Undertakings | JT-3.18 |
| Pre-Settlement | N/A |
| Other | N/A |

4. *Is the accounting standard used for regulatory purposes appropriate and is the rate-making treatment of any impacts from any changes in accounting standards, policies and estimates appropriate?*

**Complete Settlement**

The Parties agree that Hydro One will continue to report under US GAAP for regulatory purposes for the rate period from 2023 to 2027 for each of Transmission and Distribution and revenue requirement should continue to be calculated under US GAAP for regulatory purposes.

In addition, as described more particularly in Appendix 'A' of this Settlement Proposal, the Parties agree that subject to the accounting system limitations identified by Hydro One during the proceeding and the issuance by the IASB of a final IFRS Standard applicable to rate regulated utilities, Hydro One will in its next cost-based rate application provide, on a best efforts basis, estimated impacts of an initial transition from USGAAP to IFRS for regulatory purposes as at the beginning of the next rate term, as well as estimated impacts on the annual revenue requirements for the remainder of the rate term. Hydro One will also, on a best efforts and without prejudice basis, quantify the incremental costs of transitioning and maintaining IFRS for regulatory purposes.

**Approval**

| | |
|---|---|
| Parties in Support: | Anwaatin, AMPCO, CME, CCC, DRC, EP, LPMA, MFN, OSEA, PP, QMA, SEC, VECC |
| Parties Opposed: | None |
| Parties Taking No Position: | CUSW, SUP, ED, PWU, IRSS |

**Evidence**

The evidence in relation to this issue includes the following:

| | |
|---|---|
| Pre-filed Evidence | A-06-01 Accounting Information (+ Att #1)<br>C-08-02 Overhead Capitalization Rate (+ Att #2) |
| Evidence Update | N/A |
| Interrogatories | I-01-A-Staff-013 to Staff-019, I-01-C-Staff-182, I-22-A-SEC-044 to SEC-045, I-22-C-SEC-181, I-23-A-SUP-001 to SUP-005, I-24-C-VECC-022 to VECC-024 |
| Undertakings | JT-5.16, JT-5.17, JT-5.24, JT-5.32 |
| Pre-Settlement | N/A |
| Other | N/A |

## 2.0 CUSTOM APPLICATION

*5. Are all components of Hydro One's proposed Transmission Custom Incentive Rate Methodologies appropriate?*

**Complete Settlement**

The Parties accept the components of Hydro One's proposed Transmission Custom IR Methodologies, but with the modifications set out below:

- instead of a 0% X-factor for Hydro One Transmission as was proposed, the X-factor will be 0.15%; instead of a 0.15% supplemental stretch factor on capital for Hydro One Transmission as was proposed, the supplemental stretch factor will be 0.20%; and
- instead of disposing of ESM balances at Hydro One's next rebasing, ESM balances for 2021-2024 will be disposed of in Hydro One's annual update for 2026 revenue requirement.

Refer to Part B, Section 1 above for a description of the key components of the Transmission Custom IR Framework.

In addition, the Parties have agreed that, in connection with its next cost-based rate application, Hydro One will consider potential alternative approach(es) for establishing the revenue requirement and/or rates for the years following the base year, while meeting OEB RRF objectives and striking an appropriate balance of risk between customers and the utility. If Hydro One applies for another Custom IR in its next cost-based rate application, it will provide evidence regarding potential alternative approach(es) that were considered and why they were rejected.

**Approval**

| | |
|---|---|
| Parties in Support: | Anwaatin, AMPCO, CME, CCC, DRC, EP, LPMA, MFN, OSEA, PP, QMA, SEC, VECC |
| Parties Opposed: | None |
| Parties Taking No Position: | CUSW, SUP, ED, PWU, IRSS |

**Evidence**

The evidence in relation to this issue includes the following:

| | |
|---|---|
| Pre-filed Evidence | A-04-01 Custom IR Application Summary (+ Att #1)<br>A-04-02 Components of Custom IR Formula Transmission |
| Evidence Update | O-01-02 Inflation Update |
| Interrogatories | I-01-A-CLS-Staff-335 to CLS-Staff-356, I-01-A-Staff-003 to Staff-012, I-01-G-Staff-304 to Staff-305, I-01-O-Staff-361, I-04-A-CME-001, I-06-A-CCC-013 to CCC-014, I-07-A-DRC-005, I-08-A-Energy Probe-003 to Energy Probe-009, I-08-O-EnergyProbe-088, I-14-A-LPMA-003 to LPMA-005, I-22-A-SEC-010, I-22-A-SEC-035 to SEC-038, I-22-O-SEC-241, I-22-O-SEC-253, I-22-O-SEC-255, I-24-A-VECC-005 to VECC-006, I-24-A-VECC-008 |

| | |
|---|---|
| Undertakings | JT-4.08, JT-5.18 |
| Pre-Settlement | SC-22-SEC-06 |
| Other | SC Day 1 Responses – B |

*6. Are all components of Hydro One's proposed Distribution Custom Incentive Rate Methodologies appropriate?*

**Complete Settlement**

The Parties accept the components of Hydro One's proposed Distribution Custom IR Methodologies, but with the modifications set out below:

- instead of a 0.30% X-factor for Hydro One Distribution as was proposed, the X-factor will be 0.45% (consistent with the updated joint recommendation of the experts, Clearspring and PEG);
- instead of a 0.15% supplemental stretch factor on capital for Hydro One Distribution as was proposed, this supplemental stretch factor will be 0.20%; and
- instead of disposing of ESM balances at Hydro One's next rebasing, ESM balances for 2021-2024 will be disposed of in Hydro One's annual update for 2026 rates.

Refer to Part B, Section 1 above for a description of the key components of the Distribution Custom IR framework.

In addition, the Parties have agreed that, in connection with its next cost-based rate application, Hydro One will consider potential alternative approach(es) for establishing the revenue requirement and/or rates for the years following the base year, while meeting OEB RRF objectives and striking an appropriate balance of risk between customers and the utility. If Hydro One applies for another Custom IR in its next cost-based rate application, it will provide evidence regarding potential alternative approach(es) that were considered and why they were rejected.

**Approval**

| | |
|---|---|
| Parties in Support: | Anwaatin, AMPCO, CME, CCC, DRC, EP, LPMA, MFN, OSEA, PP, QMA, SEC, VECC |
| Parties Opposed: | None |
| Parties Taking No Position: | CUSW, SUP, ED, PWU, IRSS |

**Evidence**

The evidence in relation to this issue includes the following:

| | |
|---|---|
| Pre-filed Evidence | A-04-01 Custom IR Application Summary (+ Att #1)<br>A-04-03 Components of Custom IR Formula - Distribution |
| Evidence Update | O-01-02 Inflation Update |
| Interrogatories | I-01-A-CLS-Staff-335 to CLS-Staff-356, I-01-A-Staff-003 to Staff-012, I-01-G-Staff-304 to Staff-305, I-01-O-Staff-361, I-04-A-CME-001, I-06-A-CCC-013 to CCC-014, I-07-A-DRC-005, I-08-A-Energy Probe-003 to Energy Probe-009, I-08-O-EnergyProbe-088, I-22-A-SEC-010, I-22-A-SEC-035, I-22-A-SEC-039 to I-22-A-SEC-043, I-22-O-SEC-241, I-22-O-SEC-253, I-22-O-SEC-255, I-24-A-VECC-005 to VECC-006, I-24-A-VECC-008 |
| Undertakings | JT-4.08, JT-5.18 |
| Pre-Settlement | SC-22-SEC-06, SC-22-SEC-10 |
| Other | SC Day 1 Responses – B |

## 3.0 PRODUCTIVITY IMPROVEMENT AND PERFORMANCE SCOREBOARD

*7. Has Hydro One taken appropriate steps to identify and quantify productivity improvements in all areas of its Transmission and Distribution operations?*

**Complete Settlement**

For the purposes of settlement, the Parties accept the steps that Hydro One has taken to identify and quantify productivity improvements in its Transmission and Distribution operations.

**Approval**

Parties in Support: Anwaatin, AMPCO, CME, CCC, DRC, EP, LPMA, MFN, OSEA, PP, QMA, SEC, VECC
Parties Opposed: None
Parties Taking No Position: CUSW, SUP, ED, PWU, IRSS

**Evidence**

The evidence in relation to this issue includes the following:

| | |
|---|---|
| Pre-filed Evidence | B-01-01 SPF Section 1.4 Productivity Framework (+ Att #1-2) |
| Evidence Update | O-01-02 Inflation Update |
| Interrogatories | I-01-B1-Staff-024 to Staff-025, I-01-B1-Staff-027, I-01-B4-Staff-153, I-01-E-Staff-219, I-06-A-CCC-005, I-06-A-CCC-007, I-06-B1-CCC-017, I-08-A-Energy Probe-008, I-14-C-LPMA-009, I-22-A-SEC-013, I-22-B1-SEC-050 to SEC-054, I-22-B3-SEC-137, I-22-C-SEC-177 |
| Undertakings | JT-4.26, JT-4.30, JT-5.01 |
| Pre-Settlement | N/A |
| Other | N/A |

*8. Are the metrics and targets in the proposed Transmission and Distribution scorecards appropriate?*

**Complete Settlement**

The Parties agree that the metrics and targets in the proposed Transmission and Distribution OEB scorecards are appropriate. As described in Appendix 'A', the Parties further agree that for each of Distribution and Transmission, Hydro One will prepare and publish on Hydro One's website, its scorecards annually during the 2023-2027 Custom IR term to be updated to reflect capital and OM&A reductions.

**Approval**

| | |
|---|---|
| Parties in Support: | Anwaatin, AMPCO, CME, CCC, DRC, EP, LPMA, MFN, OSEA, PP, QMA, SEC, VECC |
| Parties Opposed: | None |
| Parties Taking No Position: | CUSW, SUP, ED, PWU, IRSS |

**Evidence**

The evidence in relation to this issue includes the following:

| | |
|---|---|
| Pre-filed Evidence | A-05-03 Electricity Service Quality Requirements (+Att #1)<br>B-01-01 SPF Section 1.5 Performance Measurement and Outcomes (+Att 1)<br>B-02-01 TSP Section 2.5 Performance Measurement and Outcomes (+Att 1 & 2)<br>B-03-01 DSP Section 3.5 Performance Measurement and Outcomes (+Att 1) |
| Evidence Update | N/A |
| Interrogatories | I-01-B2-Staff-045, I-01-B2-Staff-060, I-01-B2-Staff-062, I-01-B3-Staff-097 to Staff-100, I-01-B3-Staff-125, I-01-O-Staff-366, I-02-O-Anwaatin-007, I-03-B3-AMPCO-055 to AMPCO-062, I-03-B3-AMPCO-067 to AMPCO-074, I-03-O-AMPCO-130 (+ Att# 1, to 3, 5), I-03-O-AMPCO-135 (+ Att# 1 to 3, 5 to 7), I-06-A-CCC-009, I-06-A-CCC-012, I-06-O-CCC-057 (Att # 2), I-08-B2-Energy Probe-010 to Energy Probe-012, I-14-C-LPMA-010, I-18-A-PP-001, I-22-B2-SEC-082 to SEC-087, I-22-B3-SEC-130 to SEC-133, I-22-F-SEC-220, I-22-O-SEC-265 (+Att 1 to 4), I-22-O-SEC-266 (+ Att# 1 to 3), I-24-A-VECC-002 |
| Undertakings | JT-2.26, JT-3.23 |
| Pre-Settlement | SC-22-SEC-06 |
| Other | N/A |

## 4.0 TRANSMISSION SYSTEM PLAN

9. *Are the proposed Transmission capital expenditures and in-service additions arising from the Transmission System Plan appropriate, and is the rationale for planning and pacing choices (including consideration of customer preferences, planning criteria, system reliability, non-wires alternatives, facilitation of distributed energy resources, asset condition and benchmarking) appropriate and adequately explained?*

**Complete Settlement**

Subject to the modifications to the capital expenditures set out in this Proposal, the Parties agree that Hydro One's total Transmission capital expenditures will be (i) unchanged for the System Access and System Service categories, (ii) reduced by 11% ($717.7M) for the System Renewal category, and (iii) reduced by 7% ($44.6M) for the General Plant category.[58] The Parties also agree that Progressive Productivity will be held constant at $64.2M per year, as proposed. The agreed-upon reductions, represent an overall Transmission capital expenditure envelope reduction of 10% ($762.4M) over the five-year Custom IR term, relative to Hydro One's proposed Transmission capital expenditures, as shown in Part B, Section 3, Table 22 above.

The total proposed Transmission ISAs over the five-year Custom IR term have been reduced by $669.4M as shown in Part B, Section 3, Table 23 above, to reflect the impact of the capital reductions described above.

The Parties further agree that Hydro One Transmission will provide reporting, arrange for independent third-party studies to be undertaken, engage in planning processes, undertake line loss analysis, and/or address specific program requirements and other matters, each as described in Appendix 'A' and as described below:

1. **Long-Term Capital Plan Information**
   At its next cost-based rate application, Hydro One will provide a summary of long-term (10-20 years) forecast information for Hydro One Transmission and Distribution that is available in Regional Planning Reports and IESO Bulk planning. The information will be consistent with the framework being developed by the Regional Planning Process Advisory Group ("**RPPAG**"). The Parties acknowledge that this would represent a comprehensive long-term plan since it will incorporate the areas of regional planning that Hydro One is responsible for, the distribution components that are reflected within the regional plans, and the IESO's Bulk plan (which is the sole responsibility of the IESO).

[58] See Issue 15 for additional details on General Plant capital expenditures.

2. **Municipal Energy Plans**
Hydro One will meaningfully consider the goals of municipal energy and emission plans with a view to pursuing cost efficiencies, reduced emissions, and enhanced energy outcomes for consumers in Ontario served by Hydro One. Hydro One will include these elements in its next Transmission and Distribution System Plans, and the supporting Business Plan, where relevant and feasible

3. **Climate Change and Investment Planning**
Hydro One will include, in future operational and capital investments plans, discussion of how the proposed spending will directly support the achievement of Hydro One's climate change policy commitments by 2030 and 2050.

4. **Capacity Restrictions for DERs**
Hydro One will review and assess options to mitigate capacity restrictions on its Distribution system and will recommend next steps (if any) to be considered for its next DSP and TSP (or sooner for any next steps that do not have significant costs, can be accommodated within existing funding envelopes, or can be funded through other means).

**Approval**

| | |
|---|---|
| Parties in Support: | Anwaatin, AMPCO, CME, CCC, DRC, EP, ED, LPMA, MFN, OSEA, PP, QMA, SEC, VECC |
| Parties Opposed: | None |
| Parties Taking No Position: | CUSW, SUP, PWU, IRSS |

**Evidence**

The evidence in relation to this issue includes the following:

| | |
|---|---|
| Pre-filed Evidence | A-03-01 Executive Summary<br>B-01-01 SPF Section 1.2 Coordination Through Regional Planning (+ Att #1-21)<br>B-01-01 SPF Section 1.7 Investment Planning Process<br>B-02-01 TSP Section 2.0 Transmission System Plan<br>B-02-01 TSP Section 2.1 TSP Overview<br>B-02-01 TSP Section 2.2 Asset Information and Lifecycle Strategies<br>B-02-01 TSP Section 2.3 Benchmarking and Other Studies (+ Att #1 to 4)<br>B-02-01 TSP Section 2.4 Transmission System Reliability (+ Att #1 to 3)<br>B-02-01 TSP Section 2.6 Other Capital Planning Factors and Considerations<br>B-02-01 TSP Section 2.7 Investment Planning Process<br>B-02-01 TSP Section 2.8 Capital Expenditures – Overview (+ Att #1)<br>B-02-01 TSP Section 2.9 Capital Expenditures Trends And Variances (+Att #1,2)<br>B-02-01 TSP Section 2.10 Capital Work Execution<br>B-02-01 TSP Section 2.11 Material Investment Summary Documents (T-SA-01 to T-SA-10, T-SR-01 to T-SR-18, T-SS-01 to T-SS-09) |

| | |
|---|---|
| | C-02-01 Transmission In-service Additions |
| Evidence Update | O-01-01 Evidence Update – Executive Summary<br>O-01-02 Inflation Update (+ Att #1, 2, 4A, 4B, and 4G)<br>O-02-01 Evidence Update – 2021 Actuals (+ Att #1, 2, and 5) |
| Interrogatories | I-01-A-Staff-005, I-01-B2-Staff-022, I-01-B1-Staff-026, I-01-B2-Staff-028 to Staff-044, I-01-B2-Staff-046 to Staff-059, I-01-B2-Staff-061 to Staff-096, I-01-C-Staff-181, I-01-E-Staff-203, I-01-O-Staff-357, I-01-O-Staff-362 to Staff-367, I-01-O-Staff-371 to Staff-373, I-01-O-Staff-393, I-02-B2-Anwaatin-003, I-03-B1-AMPCO-002 to I-03-B2-AMPCO-050, I-03-O-AMPCO-111 to AMPCO-113, I-03-O-AMPCO-115 to AMPCO-126, I-04-A-CME-002 to CME-003, I-04-B2-CME-009 to CME-013, I-06-A-CCC-006, I-06-C-CCC-015, I-06-O-CCC-046, I-06-O-CCC-048, I-06-O-CCC-055 to CCC-056, I-07-B2-DRC-009, I-08-B2-Energy Probe-014 to Energy Probe-026, I-09-B1-ED-002 to B2-ED-014, I-09-B3-ED-017, I-09-O-ED-029, I-14-B2-LPMA-006, I-14-C-LPMA-010, I-14-O-LPMA-035, I-18-A-PP-002 to B1-PP-004, I-18-B2-PP-007 to B3-PP-013, I-18-O-PP-023, I-18-O-PP-026 to PP-027, I-19-B2-PWU-001 to PWU-002, I-22-A-SEC-002 (+ Att #1, 2), I-22-A-SEC-006 (+ Att #1), I-22-A-SEC-008, I-22-B1-SEC-046 to SEC-049, I-22-B1-SEC-056 to B2-SEC-081, I-22-B2-SEC-088 to SEC-104, I-22-B2-SEC-106 to SEC-111, I-22-B4-SEC-158, I-22-C-SEC-175 to SEC-176, I-22-O-SEC-245, I-22-O-SEC-256, I-22-O-SEC-258 (+ Att #1), I-22-O-SEC-263 (+ Att #1), I-22-O-SEC-265 (+ Att #5, 6), I-24-B2-VECC-009, I-24-C-VECC-018, I-24-E-VECC-062, I-24-O-VECC-147 to VECC-148, I-25-B1-OSEA-002 |
| Undertakings | JT-1.01 to JT-1.02, JT-1.04 to JT-1.13, JT-1.14 (Att #1, 3, and 5), JT-1.19 to JT-1.21, JT-1.23 to JT-1.27, JT-2.01 to JT-2.06, JTU-1.06, JTU-2.01 to JTU-2.02, JTU-2.06, JTU-2.22 to JTU-2.23 |
| Pre-Settlement | SC-22-SEC-02, SC-22-SEC-06, SC-22-SEC-08, SC-22-SEC-09 |
| Other | SC Day 1 Responses – A |

*10. Does Hydro One's Transmission System Plan sufficiently address the unique rights and concerns of Indigenous customers and rights-holders?*

**Complete Settlement**

For the purposes of settlement, the Parties agree that Hydro One's Transmission System Plan sufficiently addresses the unique rights and concerns of Indigenous customers and rights-holders. The Parties have included further commitments under Issue 13.

**Approval**

| | |
|---|---|
| Parties in Support: | Anwaatin, AMPCO, CME, CCC, DRC, EP, LPMA, MFN, OSEA, PP, QMA, SEC, VECC |
| Parties Opposed: | None |
| Parties Taking No Position: | CUSW, SUP, ED, PWU, IRSS |

**Evidence**

The evidence in relation to this issue includes the following:

| | |
|---|---|
| Pre-filed Evidence | A-07-02 First Nations and Metis Engagement Strategy<br>B-02-01 TSP Section 2.4, Att #1 TSP First Nations Reliability Performance |
| Evidence Update | N/A |
| Interrogatories | I-02-B2-Anwaatin-003 |
| Undertakings | JTU-2.11 |
| Pre-Settlement | N/A |
| Other | N/A |

*11. Has Hydro One appropriately considered measures to cost-effectively reduce transmission losses in its planning processes and included such measures where appropriate?*

**Complete Settlement**

For the purposes of settlement, the Parties agree that Hydro One will take certain additional steps with respect to i) the Hydro One Transmission line loss guideline, and ii) Transmission line loss assessments for material investments, as described in Appendix 'A' and below:

a) **Transmission System Line Loss Guideline Update**
Hydro One Transmission will continue participating in the IESO's transmission losses engagement process. Within six months of the final IESO guideline being published as part of the IESO stakeholder process, Hydro One will review and, if necessary, update its transmission line loss guideline.

b) **Loss Studies for Projects Not Requiring Leave to Construct**
Hydro One Transmission will prepare line loss assessments for material investments that do not require a leave to construct application and include such assessments in its TSP ISDs according to Hydro One's Transmission line loss guideline at the design phase of the project. The assessments will be filed as part of Hydro One Transmission's next cost-based rate application.

**Approval**

| | |
|---|---|
| Parties in Support: | Anwaatin, AMPCO, CME, CCC, DRC, EP, ED, LPMA, MFN, OSEA, PP, QMA, SEC, VECC |
| Parties Opposed: | None |
| Parties Taking No Position: | CUSW, SUP, PWU, IRSS |

**Evidence**

The evidence in relation to this issue includes the following:

| | |
|---|---|
| Pre-filed Evidence | B-02-01 TSP Section 2.3 Benchmarking and Other Studies (+ Att #4 - Stantec Line Loss Report)<br>B-02-01 TSP Section 2.6 Other Capital Planning Factors and Considerations |
| Evidence Update | N/A |
| Interrogatories | I-09-B2-ED-008 (+ Att #1, 2, and 3), I-09-B2-ED-009 (+ Att #1), I-09-B2-ED-010, I-22-B2-SEC-077 |
| Undertakings | N/A |
| Pre-Settlement | N/A |
| Other | N/A |

## 5.0 DISTRIBUTION SYSTEM PLAN

*12. Are the proposed Distribution capital expenditures and in-service additions arising from the Distribution System Plan appropriate, and is the rationale for planning and pacing choices (including consideration of customer preferences, planning criteria, system reliability, non-wires alternatives, facilitation of distributed energy resources, asset condition and benchmarking) appropriate and adequately explained?*

**Complete Settlement**

Subject to the modifications to the capital expenditures set out in this Proposal, the Parties agree that Hydro One's Distribution capital expenditures will be (i) unchanged for the System Access category, (ii) reduced by 21.7% ($390.2M) for the System Renewal category (after excluding AMI 2.0 related expenditures), (iii) reduced by 12% ($125.5M) for the System Service category, and (iv) reduced by 16.5% ($158.3M) for the General Plant category. The agreed-upon reductions represent an overall Distribution capital expenditure envelope reduction of 12.2% ($680.7M) over the five-year Custom IR term, relative to Hydro One's proposed Distribution capital expenditures, as shown in Table 25 in Part B, Section 4.

The Parties agree that, in recognition of the unique nature of the AMI 2.0 project and the need for it to be undertaken, there will be no reduction to capital expenditures for the AMI 2.0 project and that all referenced reductions to Distribution System Renewal capital expenditures will be applied excluding the expenditures related to AMI 2.0. The Parties also agree that the Distribution capital expenditures in relation to the AMI 2.0 project will be updated to reflect the latest information. Pursuant to the terms of the settlement agreement, AMI 2.0 project costs have been updated from the March 31st, 2022 filed amounts of $587.7M[59] to $581M to reflect the most up-to-date cost estimate as shown in Table 25 in Part B, Section 4. The Parties also agree that Hydro One will establish a new AMIVA, consistent with the scope and terms for the account as proposed in Exhibit G-01-02, Attachment 8 (a copy of which is included in

[59] Exhibit O-01-02, Attachment 4E (Distribution Capital Expenditure Summary – OEB Appendix 2-AB) dated March 31, 2022.

Attachment 3, Schedule 2.4) and as further articulated in Part C, Issue 29 (below), related to Deferral and Variance Accounts. The AMIVA will be asymmetrical to the benefit of ratepayers, such that if the revenue requirement for achieved ISAs based on actual costs and/or timing is lower than the revenue requirement for planned ISAs at the forecast cost, Hydro One Distribution would return the difference to ratepayers.

The total proposed Distribution ISAs over the five-year Custom IR term have been reduced by $665.1M as shown in Part B, Section 4, Table 26 above, to reflect the impact of the capital reductions described above.

With respect to Hydro One's Energy Storage investments (D-SS-04), the Parties agree that:

**a) Energy Storage – Grid Scale (D-SS-04)**

Hydro One Distribution shall undertake competitive procurement processes for reliability services from energy storage solution providers for projects over the 2025-2027 period and, in this regard, shall actively seek economic participation or equity investment opportunities from First Nations as part of its standard procurement practice. The terms of the procurements shall not prevent third parties from lowering the cost to Hydro One by participating in the IESO-administered markets (e.g., real-time price arbitrage, capacity services, ancillary services, etc.) as long as that participation would not unduly detract from the reliability services to Hydro One customers (i.e., the market participation could reduce the reliability benefits only by a small degree). Furthermore, Hydro One will record in a new variance account any variances in accounting treatment resulting from any third-party ownership, with disposition to be determined in the next rebasing.

**b) Energy Storage – Residential (D-SS-04)**

Hydro One confirms that the purpose of the Energy Storage – Residential (D-SS-04) investment is to improve reliability at the lowest cost to ratepayers. Parties agree that the agreement to the 2023-2027 system service capital expenditures and in-service additions shall not be construed as the Intervenor Parties necessarily agreeing that it is appropriate for Hydro One to own and operate behind-the-meter assets.

The Framework for Energy Innovation consultation (EB-2021-0118) is expected to provide regulatory clarity on the treatment of innovative technologies, including the use of third-party DERs to provide reliability improvements. Following regulatory clarity from the OEB, if there is a reputable third-party aggregator for residential battery storage units in Ontario that enables improved reliability, and that third-party aggregator expresses an interest in providing this service on reasonable terms and conditions and appropriate scale to Hydro One, then Hydro One will consider this and, if appropriate, will leverage Hydro One's existing procurement processes. In the event that this does arise, and the units are used to participate in the IESO administered markets, Hydro One will record in a new deferral account, to the benefit of ratepayers, any net revenue derived by Hydro One from the third-party's participation in the IESO administered markets, with disposition to be determined in the next rebasing.

**c) Energy Storage – Reporting (D-SS-04)**

Hydro One Distribution will prepare, and file as part of its next Distribution cost-based rate application, a baseline reliability assessment for the target customers and communities to assess the success in achieving the expected outages. The assessment will include:

- Outage frequency on a monthly basis over an historical 3-year period; and
- Outage duration on a monthly basis over an historical 3-year period.

For Grid Scale energy storage, Hydro One will provide performance data on an annual basis such as number and duration of outages experienced as well as availability of the BESS system. For residential storage, Hydro One will require the vendor's solution to be able to provide performance data on an annual basis, and Hydro One will provide the vendor's performance data on an annual basis.

The performance data will be published on the Hydro One website at the time the Capital Performance Report is published. The performance data are prepared for the purposes of Hydro One's future cost-based rate applications and will not form part of Hydro One Distribution's annual update application during the 2023-2027 Custom IR term.

The Parties agree that Hydro One will undertake, implement, prepare and/or provide the following, on terms set out below:

**d) Long-Term Capital Plan Information**

At its next cost-based rate application, Hydro One will provide a summary of long-term (10-20 years) forecast information for Hydro One Transmission and Distribution that is available in Regional Planning Reports and IESO Bulk planning. The information will be consistent with the framework being developed by the Regional Planning Process Advisory Group ("**RPPAG**"). The Parties acknowledge that this would represent a comprehensive long-term plan since it will incorporate the areas of regional planning that Hydro One is responsible for, the distribution components that are reflected within the regional plans, and the IESO's Bulk plan (which is the sole responsibility of the IESO).

**e) Electrification Planning**

As part of its next cost-based rate application, Hydro One Distribution will arrange for a study to be prepared by an independent consultant to examine general electrification scenarios for the 2030-2050 timeframe. The study will provide the directional distribution needs and recommendations for potential cost-effective solutions for electrification to minimize unit distribution costs. The consultant will invite input from the intervenors in EB-2021-0110. This study will not be a substitute for the Regional Planning process, and the specific facilities required for electrification in each Region / LDC territory will continue to be identified as part of the Regional Planning process.

For greater certainty, the words "recommendations for potential cost-effective solutions for electrification" in the above paragraph is not meant to be narrow such that it necessarily excludes consideration in the study of (a) how to size equipment to ensure it can handle potential electrification scenarios without replacement before end-of-life; (b) how to use electrification to flatten the overall load profile, improve the load factor and increase revenue to lower unit costs; (c) how to time system upgrades to match demand increases and revenue therefrom; (d) whether/how to encourage/incent efficient use of the distribution system by EVs; (e) whether/how to encourage/incent customers to utilize smart switches to "share" circuit breakers and thus avoid panel upgrades; or (f) other similar topic areas.

**f) DER Reporting**

Hydro One Distribution will publish an update of the information in the table on page 2 of JT-3.22 in EB-2021-0110, and a similar table for front-of-the-meter DERs, and provide a breakdown between behind-the-meter and front-of-the-meter resources. This information will be prepared subject to the following conditions: i) it will be published on an annual basis at the time the Capital Program Performance Report for Distribution is published; ii) upon completion it will be published on Hydro One's website; and iii) it will be prepared for the purposes of Hydro One's next Distribution cost-based rate application and will not form part of Hydro One Distribution's annual update application during the 2023-2027 Custom IR term.

**g) Municipal Energy Plans**

Hydro One will meaningfully consider the goals of municipal energy and emission plans with a view to pursuing cost efficiencies, reduced emissions, and enhanced energy outcomes for consumers in Ontario served by Hydro One. Hydro One will include these elements in its next Transmission and Distribution System Plans, and the supporting Business Plan, where relevant and feasible.

**h) Non-Wires Solutions – Planning Process**

Hydro One Distribution will develop and implement a robust planning process that appropriately considers non-wires solutions ("**NWSs**"), including CDM, to meet system service needs, which (a) includes capital and O&M cost assumptions for NWSs, (b) requires examination of NWSs in a timely fashion such that alternatives are not dismissed simply because of lack of time, and (c) includes appropriate stakeholder engagement.

Hydro One Distribution will leverage its existing procurement processes in respect of projects greater than a $5M threshold. Distribution projects will be considered for NWSs in accordance with the most recent CDM guideline, subject to a $5M threshold. This will apply on a best-efforts basis only, beginning with projects planned to commence construction in 2025. This is because the development and implementation of a robust planning process, that appropriately considers NWSs, including CDM, to meet system service needs must be developed, tested and proven to be effective and Hydro One Distribution has no experience in doing so. Once developed, tested and proven to be effective, Hydro One Distribution will apply the process in the ordinary course.

**i) Climate Change and Investment Planning**

Hydro One will include, in future operational and capital investments plans, discussion of how the proposed spending will directly support the achievement of Hydro One's climate change policy commitments by 2030 and 2050.

**j) Non-Wires Alternative Solutions – Bi-Directional Charger Study**

Hydro One Distribution, as part of its next Distribution cost-based rate application, will provide a summary of the bi-directional charger pilot program engagement,[60] results and, if possible, viable use cases.

**k) Capacity Restrictions for DERs**

Hydro One will review and assess options to mitigate capacity restrictions on its Distribution system and will recommend next steps (if any) to be considered for its next DSP and TSP (or sooner for any next steps that do not have significant costs, can be accommodated within existing funding envelopes, or can be funded through other means).

**Approval**

| | |
|---|---|
| Parties in Support: | Anwaatin, AMPCO, CME, CCC, DRC, EP, ED, LPMA, MFN, OSEA, PP, QMA, SEC, VECC |
| Parties Opposed: | None |
| Parties Taking No Position: | CUSW, SUP, PWU, IRSS |

[60] See Interrogatory B3-ED-028 part d): the pilot project with Peak Power and the IESO.

**Evidence**

The evidence in relation to this issue includes the following:

| | |
|---|---|
| Pre-filed Evidence | A-03-01 Executive Summary<br>B-01-01 SPF Section 1.2 Coordination Through Regional Planning (+ Att #1-21)<br>B-01-01 SPF Section 1.7 Investment Planning Process<br>B-03-01 DSP Section 3.0 Distribution System Plan Introduction<br>B-03-01 DSP Section 3.1 DSP Overview<br>B-03-01 DSP Section 3.2 Asset Information and Lifecycle Strategies<br>B-03-01 DSP Section 3.3 Benchmarking and Other Studies (+ Att #1, 4-8)<br>B-03-01 DSP Section 3.4 Connecting Distributed Energy Resources (+ Att #1)<br>B-03-01 DSP Section 3.6 Other Capital Planning Factors and Considerations<br>B-03-01 DSP Section 3.7 Investment Planning Process<br>B-03-01 DSP Section 3.8 Capital Expenditures – Overview (+ Att #1)<br>B-03-01 DSP Section 3.9 Capital Expenditures Trends and Variances (+Att#1-3)<br>B-03-01 DSP Section 3.10 Capital Work Execution Strategy<br>B-03-01 DSP Section 3.11 Material Investment Summary Documents (D-SA-01 to D-SA-04, D-SR-01 to D-SR-12, D-SS-01 to D-SS-06)<br>C-02-02 Distribution In-service Additions |
| Evidence Update | O-01-01 Evidence Update – Executive Summary<br>O-01-02 Inflation Update (+ Att #1, 2, 4E, 4F, and 4H)<br>O-02-01 Evidence Update – 2021 Actuals (+ Att #7, 8 and 9) |
| Interrogatories | I-01-B3-Staff-098, I-01-B3-Staff-101 to Staff-110, I-01-B3-Staff-112 to Staff-114, I-01-B3-Staff-117 to Staff-118, I-01-B3-Staff-129 to Staff-130, I-01-B3-Staff-133 to Staff-151, I-01-C-Staff-181, I-01-D-Staff-185, I-01-E-Staff-220, I-01-O-Staff-362 to Staff-369, I-02-B3-Anwaatin-004 to B4-Anwaatin-005, I-03-B3-AMPCO-051 to AMPCO-054, I-03-B3-AMPCO-063 to AMPCO-066, I-03-B3-AMPCO-075 to AMPCO-107, I-03-O-AMPCO-111, I-03-O-AMPCO-113, I-03-O-AMPCO-127 to AMPCO-128, I-03-O-AMPCO-130 to AMPCO-144, I-04-A-CME-002 to CME-003, I-04-B3-CME-014, I-04-B3-CME-017, I-06-A-CCC-006, I-06-C-CCC-016, I-06-G-CCC-041, I-06-O-CCC-046, I-06-O-CCC-056, I-07-A-DRC-001, I-07-A-DRC-004, I-07-B1-DRC-008, I-07-B3-DRC-010, I-08-B3-Energy Probe-027 to Energy Probe-044, I-08-C-Energy Probe-051 to Energy Probe-052, I-08-L-Energy Probe-080 to Energy Probe-081, I-09-A-ED-001, I-09-B3-ED-015 to ED-019a, I-09-B3-ED-023, I-09-B3-ED-027 to ED-028, I-09-E-ED-022 (Att #1), I-14-C-LPMA-011, I-14-O-LPMA-035, I-16-B1-OFA-001, I-18-A-PP-002, I-18-B1-PP-005 to PP-006, I-18-B3-PP-014 to PP-017, I-18-O-PP-023, I-18-O-PP-025 to PP-027, I-19-B3-PWU-003 to PWU-007, I-22-A-SEC-002 (+Att #3, 4), I-22-B1-SEC-048 to SEC-049, I-22-B1-SEC-059, I-22-B3-SEC-112 to SEC-123, I-22-B3-SEC-127 to SEC-129, I-22-B3-SEC-134 to SEC-136, I-22-B3-SEC-138 to SEC-157, I-22-C-SEC-175 (+Att#1), I-22-O-SEC-254, I-22-O-SEC-264 (+Att#1, 4), I-22-O-SEC-266 (+Att#5, 6), I-24-B3-VECC-010 to VECC-012, I-24-B4-VECC-016, I-24-O-VECC-147 to VECC-148, I-24-O-VECC-165, I-25-B3-OSEA-005 to OSEA-008 |

| | |
|---|---|
| Undertakings | JT-2.07 to JT-2.11, JT-2.13, JT-2.14, JT-2.21 to JT-2.24, JT-2.28 to JT-2.30, JT-3.01, JT-3.03 to JT-3.17, JT-3.21, JT-3.22, JT-3.24, JT-4.01, JT-4.07, JTU-1.06 to JTU-1.12 |
| Pre-Settlement | SC-22-SEC-02, SC-22-SEC-06, SC-22-SEC-08, SC-22-SEC-09 |
| Other | SC Day 1 Responses - A, SC Day 1 Responses – D |

*13. Does Hydro One's Distribution System Plan sufficiently address the unique rights and concerns of Indigenous customers and rights-holders?*

**Complete Settlement**

For the purposes of settlement, the Parties agree that Hydro One's Distribution System Plan sufficiently addresses the unique rights and concerns of Indigenous customers and rights-holders.

The Parties further agree that Hydro One Distribution will prepare and provide an Indigenous Reliability Report as part of its next cost-based rate application.

The Parties also agree that Hydro One Distribution will undertake competitive procurement processes for reliability services from energy storage solutions for projects over the 2025-2027 period and, in this regard, shall actively seek economic participation or equity investment opportunities from First Nations as part of its standard procurement practice. Terms of procurement and program requirements (i.e., Energy Storage – Grid Scale (D-SS-04)) in relation to the above are more particularly described in Part C, Section 5 above and Appendix A.

**Approval**

| | |
|---|---|
| Parties in Support: | Anwaatin, AMPCO, CME, CCC, DRC, EP, LPMA, MFN, OSEA, PP, QMA, SEC, VECC |
| Parties Opposed: | None |
| Parties Taking No Position: | CUSW, SUP, ED, PWU, IRSS |

**Evidence**

The evidence in relation to this issue includes the following:

| | |
|---|---|
| Pre-filed Evidence | A-07-02 First Nations and Metis Engagement Strategy (+ Att #1)<br>E-05-02 Procurement Process and Warranty Claims (+ Att #1)<br>E-09-04 Taxes Other than Income Taxes |
| Evidence Update | N/A |
| Interrogatories | I-01-B3-Staff-023, I-01-B3-Staff-129, I-02-A-Anwaatin-001 (+Att#1, 2), I-02-B1-Anwaatin-002, I-02-B3-Anwaatin-004 to Anwaatin-006 |
| Undertakings | JT-3.19 (+ Att #1) |
| Pre-Settlement | N/A |
| Other | N/A |

14. *Has Hydro One appropriately considered measures to cost-effectively reduce distribution losses in its planning processes and included such measures where appropriate?*

**Complete Settlement**

As also described in Appendix 'A', with respect to distribution system losses, the Parties agree that Hydro One Distribution will undertake the following:

- **Updated Distribution Line Loss Study**
  Hydro One Distribution will conduct an analysis of its overall distribution losses, similar to what it filed in EB-2017-0049. Should Hydro One observe a material change in overall losses, Hydro One will conduct a detailed distribution line loss study.

- **Distribution System Electricity Losses**
  Hydro One Distribution will prepare a review of utility practices for mitigating distribution system losses. The review will consider best practices of other distributors (where applicable) and provide recommendations (if any) to cost-effectively reduce losses, including details on when and how those recommendations would be implemented. The review will be provided as part of Hydro One's next distribution cost-based rate application and Hydro One will include information discussing its response to any recommendations.

- **Loss Studies for Projects Not Requiring Leave to Construct**
  Hydro One Distribution will review relevant planning standards to confirm that they will capture all cost-effective opportunities to reduce line losses when replacing infrastructure.

**Approval**

| | |
|---|---|
| Parties in Support: | Anwaatin, AMPCO, CME, CCC, DRC, EP, ED, LPMA, MFN, OSEA, PP, QMA, SEC, VECC |
| Parties Opposed: | None |
| Parties Taking No Position: | CUSW, SUP, PWU, IRSS |

**Evidence**

The evidence in relation to this issue includes the following:

| | |
|---|---|
| Pre-filed Evidence | B-03-01 TSP Section 3.6 Other Capital Planning Factors and Considerations |
| Evidence Update | N/A |
| Interrogatories | I-09-B3-ED-019b (+Att #1, 2) |
| Undertakings | JT-2.15, JT-2.17 to JT-2.19 |
| Pre-Settlement | N/A |
| Other | N/A |

## 6.0 GENERAL PLANT SYSTEM PLAN

15. *Are the proposed General Plant capital expenditures and in-service additions arising from the General System Plan appropriate, and is the rationale for planning and pacing choices (including consideration of customer preferences, planning criteria, system reliability, asset condition and benchmarking) appropriate and adequately explained?*

**Complete Settlement**

Subject to the modifications to the capital expenditures set out in this Proposal, the Parties agree that Hydro One's General Plant capital expenditures will be reduced by 7% ($44.6M) for Transmission-allocated capital expenditures and 16.5% ($158.3M) for Distribution-allocated capital expenditures. These reductions over the five-year Custom IR term are shown above in Part B, Section 3, Table 22 Table 22 - and in Part B, Section 4, Table 25.

The Transmission and Distribution General Plant ISAs over the five-year Custom IR term are shown in Part B, Section 3, Table 23 and in Part B, Section 4, Table 26 to reflect the impact of the capital reductions described above.

**Approval**

| | |
|---|---|
| Parties in Support: | Anwaatin, AMPCO, CME, CCC, DRC, EP, LPMA, MFN, OSEA, PP, QMA, SEC, VECC |
| Parties Opposed: | None |
| Parties Taking No Position: | CUSW, SUP, ED, PWU, IRSS |

**Evidence**

The evidence in relation to this issue includes the following:

| | |
|---|---|
| Pre-filed Evidence | A-03-01 Executive Summary<br>B-01-01 SPF Section 1.7 Investment Planning Process<br>B-04-01 GSP Section 4.0 Introduction<br>B-04-01 GSP Section 4.1 Overview<br>B-04-01 GSP Section 4.2 Asset Information and Lifecycle Strategies<br>B-04-01 GSP Section 4.3 Benchmarking and Other Studies (+ Att #1 to 3)<br>B-04-01 GSP Section 4.6 Other Capital Planning Factors and Considerations<br>B-04-01 GSP Section 4.7 Investment Planning Process<br>B-04-01 GSP Section 4.8 Capital Expenditures – Overview (+ Att #1)<br>B-04-01 GSP Section 4.9 Capital Expenditures – Trends and Variances (+ Att #1-2)<br>B-04-01 GSP Section 4.10 Capital Work Execution Strategy<br>B-04-01 GSP Section 4.11 Material Investment Summary Documents (G-GP-01 to G-GP-22)<br>C-02-01 - Transmission In-service Additions<br>C-02-02 - Distribution In-service Additions |

| | |
|---|---|
| Evidence Update | O-01-01 Evidence Update – Executive Summary<br>O-01-02 Inflation Update (+ Att #1, 2, 4C, 4D, 4G and 4H)<br>O-02-01 Evidence Update – 2021 Actuals (+ Att #3-5, and 9) |
| Interrogatories | I-01-A-Staff-005, I-01-B2-Staff-038, I-01-B3-Staff-136, I-01-B4-Staff-152 to Staff-179, I-01-O-Staff-357, I-01-O-Staff-362 (+ Att #1), I-01-O-Staff-365, I-01-O-Staff-370, I-03-B3-AMPCO-078, I-03-B4-AMPCO-108, I-06-A-CCC-008, I-06-B4-CCC-019 to CCC-022, I-07-A-DRC-002, I-08-B4-Energy Probe-045 to Energy Probe-050, I-09-B3-ED-024 to ED-025, I-14-B4-LPMA-007, I-14-O-LPMA-035, I-18-B4-PP-018 to PP-021, I-18-O-PP-24, I-18-O-PP-26, I-22-A-SEC-002 (+ Att #5, 6), I-22-B1-SEC-048 (+ Att # 6, 18), I-22-B2-SEC-088 to SEC-089, I-22-B2-SEC-095 (+ Att #1), I-22-B2-SEC-105, I-22-B3-SEC-135 to SEC-136, I-22-B4-SEC-158 to SEC-175 (+Att #1), I-24-B4-VECC-013 to VECC-017 |
| Undertakings | JT-2.31 to JT-2.34, JT-3.02, JT-3.20, JTU-2.14, JTU-2.15, JTU-2.19 |
| Pre-Settlement | SC-22-SEC-03 |
| Other | SC Day 1 Responses – A |

*16. Are the methodologies used to allocate Common Corporate capital expenditures to the Transmission and Distribution businesses and to determine the Overhead Capitalization Rates for the Transmission and Distribution businesses appropriate?*

**Complete Settlement**

The Parties agree that the methodologies used to allocate Common Corporate Capital expenditures to the Transmission and Distribution businesses (Allocation of Shared Assets Methodology) and to determine the Overhead Capitalization Rates for the Transmission and Distribution businesses (Overhead Capitalization Rate Methodology), are appropriate.

**Approval**

| | |
|---|---|
| Parties in Support: | Anwaatin, AMPCO, CME, CCC, DRC, EP, LPMA, MFN, OSEA, PP, QMA, SEC, VECC |
| Parties Opposed: | None |
| Parties Taking No Position: | CUSW, SUP, ED, PWU, IRSS |

**Evidence**

The evidence in relation to this issue includes the following:

| | |
|---|---|
| Pre-filed Evidence | C-03-01 Shared Asset Allocation<br>C-08-02 Overhead Capitalization Rate (+ Att #1-2)<br>E-04-08-01 Report on Corporate Cost Allocation Review – Black & Veatch |
| Evidence Update | N/A |
| Interrogatories | I-01-C-Staff-182, I-01-E-Staff-247, I-01-E-Staff-288 to Staff-289, I-08-E-Energy Probe-066, I-22-C-SEC-181, I-24-C-VECC-022 to VECC-024 |

| | |
|---|---|
| Undertakings | JT-5.24, JT-5.32 |
| Pre-Settlement | N/A |
| Other | N/A |

*17. Does Hydro One's General Plant System Plan sufficiently address the unique rights and concerns of Indigenous customers and rights-holders?*

**Complete Settlement**

For the purposes of settlement, the Parties agree that Hydro One's General Plant System Plan sufficiently addresses the unique rights and concerns of Indigenous customers and rights-holders. The Parties have included further commitments under Issue 13.

**Approval**

| | |
|---|---|
| Parties in Support: | Anwaatin, AMPCO, CME, CCC, DRC, EP, LPMA, MFN, OSEA, PP, QMA, SEC, VECC |
| Parties Opposed: | None |
| Parties Taking No Position: | CUSW, SUP, ED, PWU, IRSS |

**Evidence**

The evidence in relation to this issue includes the following:

| | |
|---|---|
| Pre-filed Evidence | A-07-02 First Nations and Metis Engagement Strategy |
| Evidence Update | N/A |
| Interrogatories | N/A |
| Undertakings | N/A |
| Pre-Settlement | N/A |
| Other | N/A |

## 7.0 OPERATIONS MAINTENANCE & ADMINISTRATION COSTS

*18. Are the proposed Transmission OM&A expenditures appropriate?*

**Complete Settlement**

The Parties agree to the proposed Transmission OM&A expenditures, subject to a 2% reduction to the proposed 2023 Transmission OM&A envelope, as shown in Part B, Section 6, Table 27 above. The Parties further agree that OM&A reductions will not be applied to Rights Payments.[61] Over the 2024 to 2027 period, Transmission OM&A expenditures will be escalated by the RCI as part of the custom IR framework described in Issue 5 above.

[61] Rights Payments are covered in Exhibit E-09-04 (Taxes Other Than Income Taxes)

In addition, as described in Issue 22 below, the Parties further agree that Hydro One will continue treating its PCB Program costs as part of Depreciation and Amortization when calculating its revenue requirement, and not as part of OM&A.

**Approval**

| | |
|---|---|
| Parties in Support: | Anwaatin, AMPCO, CME, CCC, DRC, EP, LPMA, MFN, OSEA, PP, QMA, SEC, VECC |
| Parties Opposed: | None |
| Parties Taking No Position: | CUSW, SUP, ED, PWU, IRSS |

**Evidence**

The evidence in relation to this issue includes the following:

| | |
|---|---|
| Pre-filed Evidence | E-02-01 Summary of Transmission OM&A Expenditures (+ Att #1A/1B)<br>E-02-02 Transmission Sustainment OM&A<br>E-02-03 Transmission Development OM&A<br>E-02-04 Transmission Customer Care OM&A<br>E-02-05 Transmission O&M Work Execution Strategy<br>E-04-01 Summary of Common and Other OM&A<br>E-04-02 Common Corporate Functions and Services and Other OM&A<br>E-04-03 Common Corporate OM&A - Planning<br>E-04-04 Common Corporate OM&A – Information Solutions<br>E-04-05 Operations OM&A<br>E-04-06 Common Corporate Costs OM&A - Transmission Cost of Sales - External Work<br>E-09-04 Taxes Other than Income Taxes |
| Evidence Update | O-01-01 Evidence Update – Executive Summary<br>O-01-02 Inflation Update (+ Att #1, 3A)<br>O-02-01 Evidence Update – 2021 Actuals (+ Att #6) |
| Interrogatories | I-01-B2-Staff-022, I-01-E-Staff-204, I-01-E-Staff-206 to Staff-218, I-01-E-Staff-242, I-01-E-Staff-244 to Staff-246, I-01-E-Staff-298, I-01-O-Staff-362 to Staff-366, I-01-O-Staff-374 to Staff-375, I-01-O-Staff-388, I-01-O-Staff-393, I-02-B1-Anwaatin-002, I-03-O-AMPCO-114, I-06-E-CCC-025 to CCC-027, I-06-O-CCC-054, I-06-O-CCC-057 (+ Att #3), I-08-B2-Energy Probe-013, I-08-E-Energy Probe-059(+ Att #1), I-08-E-Energy Probe-064 to Energy Probe-065, I-14-E-LPMA-021, I-14-O-LPMA-034 (+ Att #1), I-15-E-MFN-001 to MFN-002, I-18-O-PP-023, I-19-E-PWU-008 to PWU-015, I-22-A-SEC-005 (+ Att #1), I-22-A-SEC-006 (+ Att #1), I-22-A-SEC-008, I-22-B1-SEC-048 to SEC-049, I-22-E-SEC-185 to SEC-189, I-22-E-SEC-191 to SEC-193, I-24-E-VECC-059 to VECC-060, I-24-E-VECC-062 to VECC-065, I-24-E-VECC-076 |
| Undertakings | JT-1.03, JT-5.03 |
| Pre-Settlement | SC-22-SEC-02, SC-22-SEC-06, SC-22-SEC-09 |
| Other | SC Day 1 Responses – A |

*19. Are the proposed Distribution OM&A expenditures appropriate?*

**Complete Settlement**

The Parties agree to the proposed Distribution OM&A expenditures, subject to a 2% reduction to the proposed 2023 Distribution OM&A envelope, as shown in Part B, Section 6, Table 28 above. The Parties further agree that OM&A reductions will not be applied to Rights Payments.[62] Over the 2024 to 2027 period, Distribution OM&A expenditures will escalate by the RCI as part of the Distribution Custom IR Framework described in Issue 6, above.

In addition, as described in Part C, Issue 22 below, the Parties agree that Hydro One will continue treating its PCB Program costs as part of Depreciation and Amortization when calculating its revenue requirement, and not as part of OM&A.

**Approval**

| | |
|---|---|
| Parties in Support: | Anwaatin, AMPCO, CME, CCC, DRC, EP, LPMA, MFN, OSEA, PP, QMA, SEC, VECC |
| Parties Opposed: | None |
| Parties Taking No Position: | CUSW, SUP, ED, PWU, IRSS |

**Evidence**

The evidence in relation to this issue includes the following:

| | |
|---|---|
| Pre-filed Evidence | B-03-01 DSP Section 3.3 Benchmarking and Other Studies (+ Att #2, 3)<br>E-03-01 Summary of Distribution OM&A Expenditures (+ Att #1A/1B)<br>E-03-02 Distribution Sustainment OM&A<br>E-03-03 Distribution Development OM&A<br>E-03-04 Distribution Customer Care OM&A<br>E-03-05 Distribution O&M Work Execution Strategy<br>E-04-01 Summary of Common and Other OM&A<br>E-04-02 Common Corporate Functions and Services and Other OM&A<br>E-04-03 Common Corporate OM&A - Planning<br>E-04-04 Common Corporate OM&A – Information Solutions<br>E-04-05 Operations OM&A<br>E-04-07 Common Corporate Costs OM&A - Distribution Cost of Sales - External Work<br>E-09-04 Taxes Other than Income Taxes |
| Evidence Update | O-01-01 Evidence Update – Executive Summary<br>O-01-02 Inflation Update (+ Att #1, 3B)<br>O-02-01 Evidence Update – 2021 Actuals (+ Att #10) |

[62] Rights Payments are covered in Exhibit E-09-04 (Taxes Other Than Income Taxes)

| | |
|---|---|
| Interrogatories | I-01-B3-Staff-098, I-01-B3-Staff-119 to Staff-128, I-01-B3-Staff-131 to Staff-132, I-01-E-Staff-221 to Staff-237, I-01-E-Staff-242, I-01-E-Staff-244 to Staff-246, I-01-O-Staff-362 to Staff-366, I-01-O-Staff-376 to Staff-380, I-01-O-Staff-388, I-02-E-Anwaatin-006, I-03-B3-AMPCO-057, I-04-B3-CME-015 to CME-016, I-06-O-CCC-052, I-08-E-Energy Probe-059 to Energy Probe-062, I-18-O-PP-023, I-19-E-PWU-016 to PWU-017, I-22-B3-SEC-125 to SEC-126, I-22-E-SEC-190, I-22-E-SEC-194, I-22-O-SEC-254, I-24-E-VECC-067 to VECC-068, I-24-E-VECC-070 to VECC-073, I-24-E-VECC-076, I-24-E-VECC-079, I-24-E-VECC-083, I-24-O-VECC-146 |
| Undertakings | JT-3.21, JT-5.03, JTU-1.17 |
| Pre-Settlement | SC-22-SEC-02, SC-22-SEC-06, SC-22-SEC-09, SC-24-VECC-03 |
| Other | SC Day 1 Responses - A |

*20. Are the methodologies used to allocate Common Corporate OM&A Costs and Other OM&A costs to the Transmission and Distribution businesses appropriate?*

**Complete Settlement**

The Parties agree that the methodologies used to allocate Common Corporate OM&A expenditures and Other OM&A costs to the Transmission and Distribution businesses (Common Corporate Cost Allocation Methodology), as set out in the B&V Report discussed under Issue 16 are appropriate.

**Approval**

Parties in Support: Anwaatin, AMPCO, CME, CCC, DRC, EP, LPMA, MFN, OSEA, PP, QMA, SEC, VECC

Parties Opposed: None

Parties Taking No Position: CUSW, SUP, ED, PWU, IRSS

**Evidence**

The evidence in relation to this issue includes the following:

| | |
|---|---|
| Pre-filed Evidence | E-04-08 Common Corporate Costs & Allocation Methodology (+ Att #1) |
| Evidence Update | N/A |
| Interrogatories | I-01-C-Staff-182, I-01-E-Staff-247, I-01-E-Staff-288 to Staff-289, I-08-E-Energy Probe-066, I-22-C-SEC-181, I-24-C-VECC-022 to VECC-024 |
| Undertakings | JT-5.24, JT-5.32 |
| Pre-Settlement | N/A |
| Other | N/A |

21. *Are the amounts proposed to be included in the revenue requirement for income taxes appropriate?*

**Complete Settlement**

The Parties agree that the amounts to be included in the revenue requirement for income tax expenses ("**Regulatory Taxes**"), for each of the Transmission and Distribution businesses, have been appropriately determined in a manner consistent with the OEB's Filing Requirements, and are supported by detailed calculations, reconciliations and supporting schedules. The settled Regulatory Taxes in Table 37 and Table 38 below reflect the following:

- Update to Regulatory Taxes relating to the unintended exclusion of Amortization of Environmental Costs (PCB Program costs) as discussed in I-01-E-Staff-295; and
- Adjustments resulting from the application of the terms of settlement to the calculation of Regulatory Taxes, including with respect to forecasted capital, associated ISAs and OM&A.

**Table 37 - 2023 Settled Transmission Regulatory Taxes ($M)**

| | 2023 | 2024 | 2025 | 2026 | 2027 |
|---|---|---|---|---|---|
| **Proposed Regulatory Taxes**[63] | 39.8 | 70.0 | 59.1 | 80.9 | 81.7 |
| **Settled Regulatory Taxes** | 43.8 | 74.2 | 65.6 | 84.4 | 86.3 |
| **Difference** | **4.0** | **4.3** | **6.5** | **3.5** | **4.5** |

**Table 38 - 2023 Settled Distribution Regulatory Taxes ($M)**

| | 2023 | 2024 | 2025 | 2026 | 2027 |
|---|---|---|---|---|---|
| **Proposed Regulatory Taxes**[64] | 36.2 | 53.9 | 40.4 | 57.8 | 67.6 |
| **Settled Regulatory Taxes** | 39.8 | 59.3 | 47.6 | 64.0 | 72.1 |
| **Difference** | **3.6** | **5.4** | **7.1** | **6.2** | **4.5** |

Hydro One implemented an updated approach to Tax Deductible Capitalized Overheads[65] in the determination of Regulatory Taxes in the Application (the "**Updated Approach**"), which has enabled significant immediate deductions for Tax Deductible Capitalized Overheads to be incorporated into the

[63] Exhibit O-01-02, Table 24
[64] Exhibit O-01-02, Table 25
[65] As explained in Exhibit E-09-01, Section 6.3, for the purposes of determining taxable income, capitalized overhead costs are deducted immediately on the basis that they are not directly related to the acquisition or construction of capital assets and are considered recurring costs incurred as part of the day-to-day expenses of operating the business (Tax Deductible Capitalized Overheads). Tax Deductible Capitalized Overheads are based on tax legislation, jurisprudence, interpretation and principles accepted by CRA and are not dependent on accounting treatments established under accounting standards.

Application, thereby reducing Regulatory Taxes recoverable from ratepayers during the Custom IR term. To facilitate implementation of the Updated Approach used to determine Regulatory Taxes, new Capitalized Overhead Tax Variance Accounts will be established, for each of Transmission and Distribution, as further described in pre-filed evidence and in the corresponding draft accounting orders Attachment 3, Schedule 1.1 for Transmission and Attachment 3, Schedule 2.1 for Distribution.

**Approval**

| | |
|---|---|
| Parties in Support: | Anwaatin, AMPCO, CME, CCC, DRC, EP, LPMA, MFN, OSEA, PP, QMA, SEC, VECC |
| Parties Opposed: | None |
| Parties Taking No Position: | CUSW, SUP, ED, PWU, IRSS |

**Evidence**

The evidence in relation to this issue includes the following:

| | |
|---|---|
| Pre-filed Evidence | E-09-01 Corporate Income Taxes<br>E-09-02 Calculation of Utility Income Taxes (+ Att #1-6)<br>E-09-03 Hydro One Networks Inc. Income Tax Return (+ Att #1)<br>G-01-02 Capitalized Overheads Tax Variance Accounts (+ oAtt #1 and 5) |
| Evidence Update | O-02-01 Inflation Update (+ Att #09) |
| Interrogatories | I-01-E-Staff-285 to Staff-287, I-01-E-Staff-294 to Staff-297, I-22-E-SEC-218, I-22-G-SEC-225 to SEC-226 |
| Undertakings | N/A |
| Pre-Settlement | N/A |
| Other | SC Day 1 Responses - D |

*22. Is Hydro One's proposed depreciation expense appropriate?*

**Complete Settlement**

Subject to one modification related to the treatment of PCB Program Costs, the Parties agree that Hydro One's proposed depreciation expenses (depreciation and amortization), adjusted as a result of settled rate base and in-service additions for Transmission and Distribution, are appropriate.[66] The Parties agree that, with respect to the treatment of PCB Program costs, Hydro One will continue treating its PCB Program costs as part of Depreciation and Amortization in the revenue requirement, and not as part of OM&A, as initially proposed by Hydro One. As noted in Part B above, this results in the depreciation expenses as set out in Table 29 and Table 30 above in Part B, Section 7.

[66] E-08-01, Attachment 1.

**Approval**

| | |
|---|---|
| Parties in Support: | Anwaatin, AMPCO, CME, CCC, DRC, EP, LPMA, MFN, OSEA, PP, QMA, SEC, VECC |
| Parties Opposed: | None |
| Parties Taking No Position: | CUSW, SUP, ED, PWU, IRSS |

**Evidence**

The evidence in relation to this issue includes the following:

| | |
|---|---|
| Pre-filed Evidence | E-08-01 Depreciation and Amortization Expenses (+ Att #1-2) |
| Evidence Update | O-02-01 Inflation Update (+ Att #08) |
| Interrogatories | I-01-E-Staff-281 to Staff-284, I-08-E-Energy Probe-071, I-14-E-LPMA-006, I-14-E-LPMA-024, I-22-E-SEC-214 to SEC-216, I-23-E-SUP-16 to SUP-17 |
| Undertakings | N/A |
| Pre-Settlement | N/A |
| Other | N/A |

## 8.0 COMPENSATION COSTS

*23. Are the compensation related costs appropriate?*

**Complete Settlement**

Compensation related costs, including pension and OPEB costs, have been addressed in the context of agreed-upon reductions to Transmission and Distribution capital expenditures/in-service additions (Issues 9 and 12) and OM&A (Issues 18 and 19).

**Approval**

| | |
|---|---|
| Parties in Support: | Anwaatin, AMPCO, CME, CCC, DRC, EP, LPMA, MFN, OSEA, PP, QMA, SEC, VECC |
| Parties Opposed: | None |
| Parties Taking No Position: | CUSW, SUP, ED, PWU, IRSS |

**Evidence**
The evidence in relation to this issue includes the following:

| | |
|---|---|
| Pre-filed Evidence | E-06-01 Corporate Staffing and Compensation (+ Att #1-5)<br>E-07-01 Pension and OPEB Costs (+ Att #1-3) |
| Evidence Update | O-02-01 Evidence Update – 2021 Actual Results (+ Att #11) |
| Interrogatories | I-01-B4-Staff-152, I-01-E-Staff-241, I-01-E-Staff-252 to Staff-280, I-01-O-Staff-381 to Staff-383, I-01-O-Staff-385, I-03-E-AMPCO-109 to AMPCO-110, I-04-E-CME-018 to CME-021, I-06-E-CCC-033 to CCC-036, I-08-A-Energy Probe-001 to Energy Probe-002, I-08-E-Energy Probe-067 to Energy Probe-070, I-08-O-Energy Probe-082, I-14-E-LPMA-023, I-19-E-PWU-017 to PWU-019, I-22-A-SEC-004, I-22-E-SEC-198, I-22-E-SEC-201 to SEC-213, I-23-E-SUP-007 to SUP-014, I-23-O-SUP-023 to SUP-024, I-24-A-VECC-004, I-24-E-VECC-074, I-24-E-VECC-081 to VECC-082, I-24-O-VECC-146 |
| Undertakings | JT-4.15, JT-4.18 to JT-4.22, JT-4.27, JT-4.28, JT-5.08 to JT-5.13, JT 5.20, JT 5.21, JT-5.28 to JT 5.30, JTU-2.17 |
| Pre-Settlement | N/A |
| Other | SC Day 1 Responses - A |

## 9.0 RATE BASE, COST OF CAPITAL, AND REVENUE REQUIREMENT

*24. Are the amounts proposed for the Transmission and Distribution rate bases (including working capital allowances) reasonable?*

**Complete Settlement**
The Parties agree that the Transmission and Distribution rate bases, including working capital allowances, are reasonable subject to the following modifications as described below for each of the Transmission and Distribution businesses. Hydro One calculated the Transmission and Distribution rate base amounts using forecasts of net fixed assets, calculated on a mid-year average basis, plus working capital allowances. Net fixed assets are calculated as gross plant in-service minus accumulated depreciation and minus contributed capital. Working capital includes an allowance for cash working capital as well as materials and supply inventory.

The Parties agree that Hydro One's 2023 opening net fixed assets for Transmission, used to establish 2023 rate base, will reflect 2021 actuals filed on April 8, 2022 and the forecast 2022 ISAs as filed on March 31, 2022. The agreed upon 2023-2027 rate base values are set out in Part B, Section 3, Table 21, which includes the impact of the capital and the associated in-service additions reductions over 2023-2027.

The Parties agree that Hydro One's 2023 opening net fixed assets for Distribution, used to establish 2023 rate base, will reflect 2021 actuals filed on April 8, 2022 (including 2021 in-service additions and any capital spent in 2021 which resulted in ISAs in 2022 in the amount of $37.8M as further described under Part B, Section 4),[67] the forecast 2022 ISAs as filed on March 31, 2022, and $46.4M (or 50%) of the 2022 Storm Costs identified by Hydro One in JTU-2.23. The agreed upon 2023-2027 rate base values are set out in Part B, Section 4, Table 24.

**Approval**

| | |
|---|---|
| Parties in Support: | Anwaatin, AMPCO, CME, CCC, DRC, EP, LPMA, MFN, OSEA, PP, QMA, SEC, VECC |
| Parties Opposed: | None |
| Parties Taking No Position: | CUSW, SUP, ED, PWU, IRSS |

**Evidence**

The evidence in relation to this issue includes the following:

| | |
|---|---|
| Pre-filed Evidence | C-01-01 Rate Base<br>C-04-01 Statement of Utility Rate Base<br>C-04-02 Continuity of PP&E: Gross Fixed Assets<br>C-04-03 Continuity of PP&E: Accumulated Depreciation<br>C-04-04 Fixed Asset Continuity Schedules: Dx Chapter 2 Appendix 2-BA<br>C-04-05 Continuity of PP&E – Construction Work in Progress<br>C-05-01 Working Capital (+ Att #1-2)<br>C-05-02 Statement of Working Capital Test Years<br>C-05-03 Dx Chapter 2 Appendix 2-ZA: Commodity Expense Forecast and Appendix 2-ZB: Cost of Power Calculation<br>C-06-01 Materials and Supplies Inventory (+ Att #1)<br>C-07-01 Economic Evaluation True-Ups/CCRA and CCA<br>C-08-01 Interest Capitalized |
| Evidence Update | O-02-01 Inflation Update (+ Att #06A-06C) |
| Interrogatories | I-01-0-Staff-005, I-01-A-Staff-020 to Staff-021, I-01-C-Staff-180 to Staff-181, I-14-A-LPMA-002, I-14-C-LPMA-008, I-14-C-LPMA-012 to LPMA-014, I-22-C-SEC-178, I-22-O-SEC-260, I-24-C-VECC-018 to VECC-019 |
| Undertakings | JTU-1.20, JTU-2.23 |
| Pre-Settlement | N/A |
| Other | N/A |

[67] Consistent with the 2021 actual ISAs shown in Tables 2 and 5 for Transmission and Distribution respectively in Exhibit O-02-01 filed on April 8, 2022.

25. *Is the proposed cost of capital (interest on debt, return on equity) and capital structure for Transmission and Distribution appropriate?*

**Complete Settlement**

The Parties agree with the proposed cost of capital and capital structure for both the Transmission and Distribution businesses.

Hydro One's Transmission and Distribution deemed capital structures for rate-making purposes will be 60% debt and 40% common equity. The 60% debt component will be comprised of 4% deemed short-term debt and 56% long-term debt.

As noted in Part B, Section 5, the 2023 to 2027 cost of common equity for Transmission and Distribution will be based on the 2023 ROE to be established by the OEB as part of the Cost of Capital Parameters to be published in the fall of 2022. The Parties acknowledge that their agreement on ROE in this Settlement Proposal does not preclude Hydro One or any of the Intervenors from making submissions to the OEB on a generic basis as to the appropriateness of the 2023 value for the ROE resulting from the OEB's currently approved cost of capital methodology in respect of ROE (EB-2009-0084).

The 2023 to 2027 cost of short-term debt for Transmission and Distribution will be based on the 2023 short-term debt rate to be established by the OEB as part of the Cost of Capital Parameters to be published in the fall of 2022.

As noted in Part B, Section 5, the 2023 to 2027 cost of long-term debt for Transmission and Distribution will be based on Hydro One's actual 2021 and 2022 debt issuances, as well as forecasted debt issuances in 2022 and 2023 with coupon rates based on the 2022 September Consensus Forecast. Following the OEB's release of its 2023 Cost of Capital Parameters, Hydro One will also update its long-term debt rates based on its actual 2021 and 2022 debt issuances, and the forecasted debt issues in 2022 and 2023 with coupon rates based on the September 2022 Consensus Forecast.

**Approval**

| | |
|---|---|
| Parties in Support: | Anwaatin, AMPCO, CME, CCC, DRC, EP, LPMA, MFN, OSEA, PP, QMA, SEC, VECC |
| Parties Opposed: | None |
| Parties Taking No Position: | CUSW, SUP, ED, PWU, IRSS |

**Evidence**

The evidence in relation to this issue includes the following:

| | |
|---|---|
| Pre-filed Evidence | F-01-01 Cost of Capital/Capital Structure<br>F-01-02 Cost of Third-Party Long-Term Debt<br>F-01-03 Debt and Equity Summary<br>F-01-04 Cost of Long-Term Debt Capital |
| Evidence Update | O-02-01 Inflation Update (+ Att #07) |
| Interrogatories | I-01-O-Staff-397, I-08-E-Energy Probe-073, I-08-O-EnergyProbe-084, I-08-O-EnergyProbe-087, I-14-F-LPMA-025 to LPMA-026, I-23-O-SUP-020 to SUP-021, I-24-F-VECC-084 to VECC-085 |
| Undertakings | JT-5.18, JTU-2.24 |
| Pre-Settlement | SC-22-SEC-07 |
| Other | N/A |

*26. Is the proposed calculation of the Transmission and Distribution Revenue Requirements appropriate?*

**Complete Settlement**

Subject to the modifications set out in Issue 2 above, the Parties agree with the proposed calculation of the Transmission and Distribution revenue requirements. The revenue requirements for Transmission and Distribution will be calculated based on the inflation assumptions from the March 31, 2022 Evidence Update, with no further update to the inflation assumptions at the time of the DRO and no deferred recovery as proposed by Hydro One in the Evidence Update.

**Approval**

Parties in Support: Anwaatin, AMPCO, CME, CCC, DRC, EP, LPMA, MFN, OSEA, PP, QMA, SEC, VECC

Parties Opposed: None

Parties Taking No Position: CUSW, SUP, ED, PWU, IRSS

**Evidence**

The evidence in relation to this issue includes the following:

| | |
|---|---|
| Pre-filed Evidence | D-01-01 Summary of Revenue Requirement (+ Att #1-10) |
| Evidence Update | O-01-02 Inflation Update (+ Att #05A-05J)<br>O-01-04 Deferred Recovery Mechanism |
| Interrogatories | I-01-O-Staff-357, I-01-O-Staff-360, I-08-O-Energy Probe-083, I-14-LPMA-029, I-14-LPMA-032, I-22-O-SEC-246, I-22-O-SEC-253, I-23-O-SUP-018, I-24-O-VECC-149, I-24-O-VECC-171, I-24-O-VECC-165 |
| Undertakings | JTU-1.17, JTU-1.21 |
| Pre-Settlement | SC-22-SEC-02, SC-22-SEC-06 |
| Other | N/A |

## 10.0 LOAD FORECAST

*27. Are the load forecast methodologies and the resulting load forecasts appropriate for each of Transmission and Distribution?*

**Complete Settlement**

The Parties agree that Hydro One will use the proposed methodologies to determine its Transmission and Distribution load forecasts, subject to the load forecasts for each of Transmission and Distribution being modified by reducing the assumptions for incremental achievable potential CDM by 100% for each of 2023 and 2024, and by 35% for each of the years from 2025-2027, relative to what was included in the updated load forecasts filed by Hydro One on March 31, 2022.

The agreed-upon load forecasts resulting from this modification are presented in Part A, Section 5, Table 7 and Table 8.

**Approval**

| | |
|---|---|
| Parties in Support: | Anwaatin, AMPCO, CME, CCC, DRC, EP, LPMA, MFN, OSEA, PP, QMA, SEC, VECC |
| Parties Opposed: | None |
| Parties Taking No Position: | CUSW, SUP, ED, PWU, IRSS |

**Evidence**

The evidence in relation to this issue includes the following:

| | |
|---|---|
| Pre-filed Evidence | D-03-01 Hydro One Load Forecast – Key Economic and Demographic Assumptions (+Att #1)<br>D-04-01 Transmission Load Forecast and Methodology (+Att #1)<br>D-05-01 Distribution Load Forecast and Methodology (+Att #1, 2, 3) |
| Evidence Update | O-01-03 Load Forecast Update |
| Interrogatories | I-01-B3-Staff-135, I-01-B3-Staff-148, I-01-D-Staff-186 to Staff-202, I-01-L-Staff-328, I-01-L-Staff-334, I-01-O-Staff-393 to Staff-395, I-04-A-CME-006, I-04-O-CME-023, I-06-A-CCC-010, I-07-A-DRC-005 to DRC-006, I-07-O-DRC-011 to DRC-012, I-08-D-EnergyProbe-056 to EnergyProbe-058, I-08-O-EnergyProbe-089 to EnergyProbe-090, I-14-D-LPMA-015 to LPMA-018, I-14-O-LPMA-038 to LPMA-041, I-22-O-SEC-247; I-24-D-VECC-035 to VECC-058, I-24-G-VECC-089 to VECC-093, I-24-H-VECC-104, I-24-L-VECC-109, I-24-L-VECC-111 to VECC-112, I-24-O-VECC-151 to VECC-162, I-25-D-OSEA-003 to OSEA-004, I-25-O-OSEA-009 |
| Undertakings | JT-3.03, JT-3.25, JT-4.06, JT-VECC-TCQ-01-13, JT-VECC-TCQ-18, JTU 2.27 |
| Pre-Settlement | SC-24-VECC-04, SC-24-VECC-05 |
| Other | N/A |

## 11.0 DEFERRAL/VARIANCE ACCOUNTS

*28. Are the proposed amounts for disposition, and the continuance or discontinuation of Hydro One's existing deferral and variance accounts for each of Transmission and Distribution appropriate?*

**Complete Settlement**

The Parties agree that the proposed amounts for disposition, and the continuance or discontinuation of Hydro One's existing deferral and variance accounts ("**DVAs**") for each of Transmission and Distribution are appropriate, as follows.

Transmission

i. Amounts for Disposition

Hydro One will dispose of the amounts it proposed for disposition, subject to the modification that disposition of all Transmission DVA balances will be over a 1-year period in 2023 (rather than the five-year period proposed in the Application). Moreover, the Account 1592 Sub-account CCA Changes balance was calculated using actual additions.

The Transmission DVA amount to be disposed of in 2023 is a credit balance of $22.5M which consists of audited 2020 balances inclusive of projected carrying costs to December 31, 2022, adjusted for OEB-approved dispositions in 2021 and 2022 from the prior Transmission cost-based rate application (including a life-to-date credit adjustment to External Station Maintenance, E&CS and Other External Revenues variance account relating to the 2013 to 2020 years). The amounts to be disposed of for Transmission are summarized in Part B, Section 10, Table 35.

ii. Continuance of Transmission DVAs[68]

The following 16 Transmission DVAs will be continued:

- Long-Term Transmission Future Corridor Acquisition and Development Deferral Account (Account 1508)
- Other Post-Employment Benefits (OPEB) Cost Deferral Account (Account 1508)
- Customer Connection and Cost Recovery Agreements (CCRA) True-Up Variance Account (Account 1508)
- Tax Rate Changes Variance Account (Account 1592)[69]
- Excess Export Service Revenue Variance Account (Account 2405)
- External Secondary Land Use Revenue Variance Account (Account 2405)

---

[68] With respect to the LDC CDM and Demand Response Variance Account, the account is not proposed for continuation to capture any new variances for 2023-2027 rate years; however, any principal balances booked in 2021 with respect to 2018 and 2019 will be brought forward for disposition in a future rate application.

[69] Hydro One will continue to track (in the CCA Changes Sub-Account) the impact, if any, arising from legislative changes relating to Accelerated CCA during the 2023-2027 application period.

- External Station Maintenance, E&CS Revenue and Other External Revenue Variance Account (Account 2405)
- Pension Cost Differential Variance Account (Account 2405)
- External Revenue – Partnership Transmission Projects Deferral Account (Account 2405)
- Depreciation Expense (Asset Removal Costs) Asymmetrical Cumulative Variance Account (Account 2405)
- Earnings Sharing Mechanism (ESM) Deferral Account (Account 2435)
- Capital Contribution Recovery Differential Account – Barrie Area Transmission Upgrade – BATU (Account 1508)
- Other Regulatory Assets, Sub-Account Misallocated Future Tax Savings Carrying Charges for Transmission (Account 1508)
- OPEB Asymmetrical Carrying Charge Variance Account (Account 1522) (Modified per Issue 29 below)
- Pension and OPEB Forecast Accrual versus Actual Cash Payment Differential Variance (Account 1522) (Modified per Issue 29 below)
- Rights Payment Variance Account (Account 2405) (Modified per Issue 29 below)

iii. Discontinuation of Transmission DVAs

The following 7 Transmission DVAs will be discontinued:

- Waasigan Transmission Line Tracking Deferral Account (Account 1508)[70]
- Transmission COVID-19 Emergency Deferral Account (Account 1509)
- Transmission Capital in Service Variance Account (CISVA, Account 2405)
- East-West Tie Tracking Account (Account 1508)
- Supply to Essex County Transmission Reinforcement (SECTR) Tracking Account (Account 1508)
- Integrated System Operating Center (ISOC) Asymmetrical Variance Account – Transmission (Account 2405)
- Foregone Revenue Deferral Account (Account 1508)

Distribution

**1.** Amounts for Disposition

Hydro One will dispose of the amounts it proposed for disposition, subject to the modification that the total balance of all Group 1 and 2 Distribution DVAs will be disposed of over a 3-year period from 2023 to 2025 (rather than the five year period proposed in the Application) subject to the caveat that if necessary for purposes of rate mitigation this disposition period may be

[70] On October 7, 2021, the OEB approved Hydro One's request to establish the Affiliate Transmission Projects (ATP) Account effective May 28, 2021. The Waasigan Transmission Line Tracking Deferral Account was subsequently closed and transferred to the ATP Account.

adjusted with the further agreement of the Parties. Moreover, the Account 1592 Sub-account CCA Changes balance was calculated using actual additions.

The Distribution DVA amount (inclusive of Group 1 and 2 balances) to be disposed of from 2023 to 2025 is a credit balance of $85.9M, which consist of its audited 2020 balances inclusive of projected carrying costs to December 31, 2022, adjusted for OEB approved dispositions in 2021. The amounts to be disposed of for Distribution are summarized in Part B, Section 11, Table 36

Further, in the OEB's Decision and Order on the Motion to Review and Vary for the Acquired Utilities (EB-2022-0071), the OEB directed Hydro One to calculate its Account 1592 entries for 2018-2022 using the Actual Additions Method with the resulting balances to be disposed of in the current proceeding (EB-2021-0110).[71] The OEB subsequently approved the balances for Account 1592, Sub-account CCA Changes, for each of the Acquired Utilities, on the basis that their disposition, along with carrying charges up to the effective date of disposition, would be addressed in the current Application.[72] Consistent with the disposition of the Hydro One Distribution balances over a 3-year period, the CCA balances presented in Table 39 below for the Acquired Utilities to be disposed of in this proceeding through the Acquired Utilities' rate classes.

**Table 39 - Forecast CCA Balances as of December 31, 2022**

| | | **Principal as at December 31, 2022 *** | **Interest as at December 31, 2022** | **Total Balance as at December 31, 2022** |
|---|---|---|---|---|
| 1592 | Former Norfolk Power Distribution Inc. | ($409,552) | ($10,863) | ($420,415) |
| 1592 | Former Haldimand County Hydro Inc. | ($482,572) | ($11,339) | ($493,911) |
| 1592 | Former Woodstock Hydro Services Inc. | ($337,486) | ($7,484) | ($344,970) |
| **Total** | | **($1,229,609)** | **($29,687)** | **($1,259,296)** |

*Exhibit reference: EB-2022-0071, Decision and Order, May 12, 2022, p. 2*
** In EB-2022-0071, the OEB approved Account 1592, Sub-account CCA Changes balances in Table 1, forecast to December 31, 2022 for each of the Acquired Utilities.*

**2.** Continuation of Distribution DVAs

The following 15 Distribution DVAs will be continued:

- Smart Meter Entity (SME) Charge Variance Account (Account 1551)
- Retail Settlement Variance Account (Accounts 1580-1589)
- Pension Cost Differential Variance Account (Account 2405)
- Tax Rate Changes Variance Account (Account 1592)[73]
- Long term Load Transfer (LTLT) Rate Impact Mitigation Deferral Account (Account 1508)

[71] EB-2022-0071, Decision and Order, April 7, 2022, pp. 6, 9 and 11.
[72] EB-2022-0071, Decision and Order, May 12, 2022, p. 2.
[73] Hydro One will continue to track (in the CCA Changes Sub-Account) the impact, if any, arising from legislative changes relating to Accelerated CCA during the 2023-2027 application period.

- Earnings Sharing Mechanism (ESM) Deferral Account (Account 2435)
- OPEB Cost Deferral Account (Account 1508)
- Distribution Generation – Provincial - Other Costs – Deferral Account (Account 1533)
- Distribution Generation - Provincial - Express Feeders - Deferral Account (Account 1533)
- Account 1595 – Disposition and Recovery/Refund of Regulatory Balances, Sub-Account Principal Balances of Misallocated Future Tax Savings for Distribution
- Account 1595 – Disposition and Recovery/Refund of Regulatory Balances, Sub-Account Misallocated Future Tax Savings Carrying Charges for Distribution
- Account 1595 (2019) – Disposition and Recovery of Regulatory Balances (OEB Approved) Deferral Account
- Account 1595 (2021) – Disposition and Recovery of Regulatory Balances (OEB Approved)
- OPEB Asymmetrical Carrying Charge Variance Account (Account 1522) (Modified per Issue 29 below)
- Pension and OPEB Forecast Accrual versus Actual Cash Payment Differential Variance (Account 1522) (Modified per Issue 29 below)

**3.** Discontinuation of Distribution DVAs

Hydro One will discontinue the following 7 Distribution DVAs:

- Distribution COVID-19 Emergency Deferral Account (Account 1509)
- Distribution Capital in Service Variance Account (CISVA, Account 2405)
- Integrated System Operating Center (ISOC) Asymmetrical Variance Account – Distribution (Account 2405)
- Customer Choice Initiative Deferral Account (Account 1508)[74]
- Smart Grid Fund (SGF) Pilot Deferral Account (Account 1508)
- Retail Cost Variance Account (Accounts 1518 and 1548)
- Group 2 accounts of the Acquired LDCs (Norfolk, Woodstock, Haldimand) consistent with the OEB's decision in EB-2021-0033[75]

[74] In Exhibit G-01-02, Hydro One Distribution proposed the discontinuation of this account on the basis that it was anticipated all costs would be captured in the deferral account by the end of 2021. As costs were still incurred in 2022, amounts recorded up to December 31, 2022 are still eligible to be brought forth for disposition in a future rate proceeding. No costs will be recorded in the account starting in 2023.

[75] Through the 2022 Annual Update for the Acquired Utilities in EB-2021-0033, Hydro One requested and was approved to discontinue all of the Acquired Utilities' Group 2 accounts after 2022, with the exception of Haldimand's Account 1533 which was approved for continuation in EB-2021-0033, Decision and Order, December 21, 2021, p. 9.

**Approval**

| | |
|---|---|
| Parties in Support: | Anwaatin, AMPCO, CME, CCC, DRC, EP, ED, LPMA, MFN, OSEA, PP, QMA, SEC, VECC |
| Parties Opposed: | None |
| Parties Taking No Position: | CUSW, SUP, PWU, IRSS |

**Evidence**

The evidence in relation to this issue includes the following:

| | |
|---|---|
| Pre-filed Evidence | G-01-01 Regulatory Accounts (+ Att #1-5)<br>G-01-03 Proposed Disposition of Regulatory Accounts (+ Att #1-2)<br>G-01-04 Schedule of Annual Recoveries<br>G-01-05 Proposed Disposition of Regulatory Accounts (+ Att #1-3) |
| Evidence Update | O-01-05 Update on Transmission External Revenues Variance Account (+Att#1) |
| Interrogatories | I-01-G-Staff-276, I-01-G-Staff-299, I-01-G-Staff-301 to Staff-303, I-01-G-Staff-308 to Staff-310, I-01-G-Staff-316, I-01-G-Staff-318, I-06-G-CCC-037 to CCC-038, I-08-G-Energy Probe-074, I-14-G-LPMA-028, I-22-A-SEC-003, I-22-A-SEC-012, I-22-G-SEC-223, I-24-G-VECC-094, I-24-O-VECC-173 to VECC-175 |
| Undertakings | JT-4.13, JT-4.23, JT-5.28 |
| Pre-Settlement | SC-24-VECC-01 |
| Other | SC Day 1 Responses – D |

*29. Are the proposed new or modified Transmission and Distribution deferral and variance accounts appropriate?*

**Complete Settlement**

The Parties agree that Hydro One will establish the new Transmission and Distribution DVAs, or modify the existing Transmission and Distribution DVAs, as follows:

Transmission

a) New Transmission DVAs
- Capitalized Overheads Tax Variance Account (Transmission)[76] with the draft accounting order provided in **Attachment 3, Schedule 1.1**.
- Externally Driven Transmission Projects Variance Account[77] with the draft accounting order provided in **Attachment 3, Schedule 1.2**. The baselines (consistent with SC-SEC Interrogatory-01) for Capital and ISA are provided in Table 40 below:

[76] Further described in Exhibit G-01-02, Section 4.1
[77] Further described in Exhibit G-01-02, Section 4.2, and in interrogatory responses to G-Staff-304

**Table 40 - Baselines for Externally Driven Transmission Projects Variance Account**

| $M | 2023 | 2024 | 2025 | 2026 | 2027 |
|---|---|---|---|---|---|
| **Capital (Total)** | **85.8** | **49.9** | **41.7** | **67.5** | **58.6** |
| T-SA-04 - Connect Metrolinx Traction Substations | 3.7 | 3.8 | 0.9 | - | - |
| T-SA-07 - Secondary Land Use Projects | 39.8 | 3.0 | 3.0 | 0.9 | 0.9 |
| T-SS-02 - St. Lawrence TS: Phase Shift Replacement | 6.3 | - | - | - | - |
| T-SS-03 - Merivale TS to Hawthorne TS: 230kV Conductor Upgrade | 9.5 | - | - | - | - |
| T-SS-04 - Richview x Trafalgar 230kv Conductor Upgrade | 13.3 | 17.2 | 12.7 | 2.5 | - |
| T-SS-07 - West Chatham Reinforcement | 8.8 | 21.4 | 5.5 | - | - |
| T-SS-09 - West of London Reinforcement | 4.4 | 4.5 | 19.6 | 64.1 | 57.7 |
| | | | | | |
| **ISA (Total)** | **89.7** | **9.7** | **42.3** | **53.5** | **81.7** |
| T-SA-04 - Connect Metrolinx Traction Substations | - | 6.9 | 1.5 | - | - |
| T-SA-07 - Secondary Land Use Projects | 44.5 | 2.8 | 3.0 | 1.4 | 0.9 |
| T-SS-02 - St. Lawrence TS: Phase Shift Replacement | 35.7 | - | - | - | - |
| T-SS-03 - Merivale TS to Hawthorne TS: 230kV Conductor Upgrade | 9.5 | - | - | - | - |
| T-SS-04 - Richview x Trafalgar 230kv Conductor Upgrade | - | - | - | 52.1 | - |
| T-SS-07 - West Chatham Reinforcement | - | - | 37.8 | - | - |
| T-SS-09 - West of London Reinforcement | - | - | - | - | 80.8 |

- Transmission Sale of Properties Deferral Account, which will include two sub-accounts: 1) A Revenue Requirement Impacts sub-account to record the revenue requirement impact, including taxes, associated with the rate base component of the sold land and buildings in the General Plant Facilities and Real Estate portfolio, which are being recovered in rates but no longer owned by Hydro One during all or part of the 2023-2027 Custom IR term. 2) A Gain/Loss on Sale sub-account to record the after-tax gains or losses from the sale of land and buildings in the General Plant Facilities and Real Estate portfolio recovered in rates, during the 2023-2027 Custom IR term. The prudence review will include amounts related to the sale price, gain/losses, and the impacts to rate base, including the timing of when the property is removed from rate base not only amounts related to properties where impacts and gain/losses have been included in the account, but also if there are other properties that are no longer used or useful and that commercially reasonably could have been disposed of, but were not. A draft accounting order for the Transmission Sale of Properties Deferral Account is provided in **Attachment 3, Schedule 1.4.**

- Transmission Clean Energy Tax Credit Deferral Account to record the revenue requirement impacts of eligible new tax credits associated with investments in net-zero technologies, battery storage solutions and clean hydrogen that may be established by the Government of Canada, as contemplated at p. 94 of the 2022 Federal Budget issued on April 7, 2022, which will be disposed of in the next Transmission cost-based rate application. A draft accounting order for the Transmission Clean Energy Tax Credit Deferral Account is provided in **Attachment 3, Schedule 1.5.**

b) Modifications to Existing Transmission DVAs
   - Rights Payments Variance Account (Account 2405)[78] with the draft accounting order provided in **Attachment 3, Schedule 1.3**
   - OPEB Asymmetrical Carrying Charge Variance Account (Account 1522)[79] with the draft accounting order provided in Attachment 3, Schedule 1.6
   - Pension and OPEB Forecast Accrual Versus Actual Cash Payment Differential Variance Tracking Account (Account 1522)[80] with the draft accounting order provided in Attachment 3, Schedule 1.6

c) As the Parties agreed not to establish the deferred recovery mechanism as proposed by Hydro One in the Evidence Update, the related request to approve the "Transmission Approved Revenue Requirement Deferral Account" is no longer required.

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[78] Further described in Exhibit G-01-02, Section 4.4
[79] Further described in Exhibit G-01-02, Section 4.5
[80] Further described in Exhibit G-01-02, Section 4.6

Distribution

a) New Distribution DVAs

- Capitalized Overheads Tax Variance Account (Distribution)[81] with the draft accounting order provided in **Attachment 3, Schedule 2.1**.
- Distribution Connection Cost Agreement (CCA) Variance Account[82] with the draft accounting order provided in **Attachment 3, Schedule 2.3**.
- AMI 2.0 Variance Account (AMIVA) [83] with the draft accounting order provided in **Attachment 3, Schedule 2.4**.
- Depreciation Expense (Asset Removal Costs) Asymmetrical Cumulative Variance Account[84] with the draft accounting order provided in **Attachment 3, Schedule 2.5**.
- Externally Driven Distribution Projects Variance Account. With respect to this account, the Parties agree that the scope of the account will be in relation to 1) Joint Use and Relocations (D-SA-01), and 2) variances in relation to Customer Demand DER (D-SA-03) upgrades or DER connections, but only where triggered by specific IESO procurement initiatives.[85] A draft accounting order reflecting the modified scope of this account, as agreed to in settlement, is provided in **Attachment 3, Schedule 2.2**. The baselines (consistent with SC-SEC Interrogatory-01) for Capital and ISA are provided in Table 41 below:

**Table 41 - Baselines for Externally Driven Distribution Projects Variance Account**

| $M | 2023 | 2024 | 2025 | 2026 | 2027 |
|---|---|---|---|---|---|
| **Capital (Total)** | **27.6** | **32.0** | **29.9** | **29.4** | **30.2** |
| D-SA-01 - Joint Use and Relocations | 26.1 | 30.5 | 28.4 | 27.9 | 28.7 |
| D-SA-03 - Customer Demand Distribution Energy Resources | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 |
| | | | | | |
| **ISA (Total)** | **28.2** | **32.8** | **30.0** | **29.4** | **30.1** |
| D-SA-01 - Joint Use and Relocations | 25.6 | 30.2 | 28.5 | 27.9 | 28.6 |
| D-SA-03 - Customer Demand Distribution Energy Resources | 2.6 | 2.6 | 1.5 | 1.5 | 1.5 |

[81] Further described in Exhibit G-01-02, Section 7.1
[82] Further described in Exhibit G-01-02, Section 7.3
[83] Further described in Exhibit G-01-02, Section 7.4
[84] Further described in Exhibit G-01-02, Section 7.5
[85] Further described in Exhibit G-01-02, Section 7.2, and in interrogatory responses to G-Staff-304

- Distribution Sale of Properties Deferral Account, which will include two sub-accounts: 1) A Revenue Requirement Impacts sub-account to record the revenue requirement impact, including taxes, associated with the rate base component of the sold land and buildings in the General Plant Facilities and Real Estate portfolio, which are being recovered in rates but no longer owned by Hydro One during all or part of the 2023-2027 Custom IR term. 2) A Gain/Loss on Sale sub-account to record the after-tax gains or losses from the sale of land and buildings in the General Plant Facilities and Real Estate portfolio recovered in rates, during the 2023-2027 Custom IR term. The prudence review will include amounts related to the sale price, gain/losses, and the impacts to rate base, including the timing of when the property is removed from rate base not only amounts related to properties where impacts and gain/losses have been included in the account, but also if there are other properties that are no longer used or useful and that commercially reasonably could have been disposed of, but were not. A draft accounting order for the Distribution Sale of Properties Deferral Account is provided in **Attachment 3, Schedule 2.6**.

- Distribution Clean Energy Tax Credit Deferral Account to record the revenue requirement impacts of eligible new tax credits associated with investments in net-zero technologies, battery storage solutions and clean hydrogen that may be established by the Government of Canada, as contemplated at p. 94 of the 2022 Federal Budget issued on April 7, 2022, which will be disposed of in the next Distribution cost-based rate application. A draft accounting order for the Distribution Clean Energy Tax Credit Deferral Account is provided in **Attachment 3, Schedule 2.7**.

- Distribution System Energy Storage - Grid Scale Third-Party Accounting Treatment Variance Account to record the difference in the revenue requirement impact between Hydro One's current accounting treatment of the forecast costs as set out in the D-SS-04 for a grid scale energy storage project, and any alternative accounting treatment informed by any future OEB guidance pertaining to cost recovery for innovative solutions, if Hydro One enters into an arrangement with a third-party to provide reliability services. A draft accounting order for the Distribution System Energy Storage - Grid Scale Third-Party Accounting Treatment Variance Account is provided in Attachment 3, Schedule 2.8.

- Distribution System Energy Storage – Residential Deferral Account. Hydro One may procure the services of a third-party aggregator in respect of its residential battery storage units associated with the residential energy storage investments in D-SS-04. To the extent that these third-party units are used to participate in IESO markets and if such participation generates net revenues to the benefit of Hydro One, Hydro One will record the net revenue in the Residential Deferral Account, if any. A draft accounting order for the Distribution System Energy Storage – Residential Deferral Account is provided in Attachment 3, Schedule 2.9.

b) Modifications to Existing Distribution DVAs:
- OPEB Asymmetrical Carrying Charge Variance Account (Account 1522)[86], with the draft accounting order provided in Attachment 3, Schedule 2.10
- Pension and OPEB Forecast Accrual Versus Actual Cash Payment Differential Variance Tracking Account (Account 1522),[87] with the draft accounting order provided in Attachment 3, Schedule 2.10

c) As the Parties agreed not to establish the deferred recovery mechanism as proposed by Hydro One in the Evidence Update, the related request to approve the "Distribution Approved Revenue Requirement Deferral Account" is no longer required.

**Approval**

| | |
|---|---|
| Parties in Support: | Anwaatin, AMPCO, CME, CCC, DRC, EP, ED, LPMA, MFN, OSEA, PP, QMA, SEC, VECC |
| Parties Opposed: | None |
| Parties Taking No Position: | CUSW, SUP, PWU, IRSS |

**Evidence**

The evidence in relation to this issue includes the following:

| | |
|---|---|
| Pre-filed Evidence | G-01-02 Regulatory Accounts Requested (+ Att #1-10) |
| Evidence Update | O-01-04 Deferred Recovery Mechanism (+ Att #1-2) |
| Interrogatories | I-01-G-Staff-300, I-01-G-Staff-304, I-01-G-Staff-317, I-06-G-CCC-039 to CCC-041, I-22-G-SEC-225 to SEC-230, I-24-A-VECC-007, I-24-G-VECC-086 to VECC-088, I-24-O-VECC-166, I-24-O-VECC-171 |
| Undertakings | JT-2.34, JT-5.14, JT-5.27 |
| Pre-Settlement | SC-22-SEC-01 (+Att 1), SC-22-SEC-03 |
| Other | N/A |

[86] Further described in Exhibit G-01-02, Section 7.6
[87] Exhibit G-01-02, Section 7.7

## 12.0 COST ALLOCATION FOR TRANSMISSION

*30. Is the proposed Transmission cost allocation appropriate?*

**Complete Settlement**

The Parties agree that the proposed Transmission cost allocation is appropriate.

**Approval**

| | |
|---|---|
| Parties in Support: | Anwaatin, AMPCO, CME, CCC, DRC, EP, LPMA, MFN, OSEA, PP, QMA, SEC, VECC |
| Parties Opposed: | None |
| Parties Taking No Position: | CUSW, SUP, ED, PWU, IRSS |

**Evidence**

The evidence in relation to this issue includes the following:

| | |
|---|---|
| Pre-filed Evidence | H-01-01 Cost Allocation and Rate Pool Revenue Requirement<br>H-01-02 Description of Transmission Cost Allocation Methodology<br>H-01-03 Network, Line Connection and Transformation Connection Rate Pools |
| Evidence Update | N/A |
| Interrogatories | I-01-A-Staff-003, I-22-O-SEC-252, I-24-H-VECC-95 to VECC-103,<br>I-24-H-VECC-105 to VECC-106 |
| Undertakings | JT-VECC-TCQ-14 |
| Pre-Settlement | N/A |
| Other | N/A |

## 13.0 COST ALLOCATION AND RATE DESIGN FOR DISTRIBUTION

*31. Is the proposed Distribution cost allocation appropriate?*

**Complete Settlement**

The Parties agree that, subject to the following, the proposed Distribution cost allocation is appropriate:

- In the 2023 Distribution Cost Allocation Model, Hydro One will change the meter reading weighting factor for the GSd and Gse rate classes from 1.25 to 1.6. The locations of GSd and Gse customers are about equally split between medium and low density areas. Using a weighted average of the meter reading weighting factors between the medium density and low density residential rate classes more appropriately reflects the density of GSd and Gse customers;[88]

[88] Per Exhibit 1, Tab 1, Schedule L-Staff-326, part e and Technical Conference Transcript December 16, 2021, pages 60 -61.

- Hydro One will include UsofA 1815 asset costs and asset retirements in the direct allocation factor calculations as set out in Undertaking JT-VECC-TCQ-19; and
- Hydro One will track capital additions by Acquired LDC and by UsofA 1815 to 1860 until the next Distribution cost-based rate application.

**Approval**

| | |
|---|---|
| Parties in Support: | Anwaatin, AMPCO, CME, CCC, DRC, EP, ED, LPMA, MFN, OSEA, PP, QMA, SEC, VECC |
| Parties Opposed: | None |
| Parties Taking No Position: | CUSW, SUP, PWU, IRSS |

**Evidence**

The evidence in relation to this issue includes the following:

| | |
|---|---|
| Pre-filed Evidence | L-01-01 Introduction to Cost Allocation and Rate Design<br>L-01-02 Distribution Customer Classification<br>L-01-03 Distribution Cost Allocation (+ Att #1-3) |
| Evidence Update | N/A |
| Interrogatories | I-01-L-Staff-321, I-01-L-Staff-323 to Staff-328, I-18-O-PP-022, I-22-L-SEC-233 to SEC-236, I-22-O-SEC-252 (+ Att #1), I-24-L-VECC-108 to VECC-120, I-24-L-VECC-125 to VECC-126, I-24-L-VECC-128, I-24-L-VECC-133 to VECC-134, I-24-O-VECC-164 |
| Undertakings | JT-VECC-TCQ-09, JT-VECC-TCQ-15 to 20, JT-VECC-TCQ-19-Att# 1-3, JT-VECC-TCQ-24 to 25 |
| Pre-Settlement | SC-24-VECC-05, SC-24-VECC-06 |
| Other | N/A |

*32. Is the proposed Distribution rate design appropriate?*

**Complete Settlement**

The Parties agree that, subject to the following, the proposed Distribution rate design is appropriate:

- Hydro One will perform calculations of Customer Supplied Transformer Allowance (CSTA) rate adders on a class specific basis, which will result in unique CSTA rate adders for each of the following rate classes: Dgen, GSd, Ugd, AUGd and AGSd;

- For all non-residential rate classes, Hydro One will establish its 2023 to 2027 fixed charges such that the fixed/variable split is maintained in accordance with the following principles:
  - If the current (2022) fixed charge is above the Customer Unit Cost per Month – minimum System with PLCC Adjustment in the 2023 Cost Allocation Model,
    - in years where maintaining the current fixed/variable revenue split results in a higher fixed charge than the previous year, Hydro One will maintain the fixed charge at the previous year's level, and

    - in years where maintaining the current fixed/variable revenue split results in a lower fixed charge than the previous year, Hydro One will lower the fixed charge to the lower value;
  - If the current (2022) fixed charge is below or equal to the Customer Unit Cost per Month – minimum System with PLCC Adjustment in the 2023 Cost Allocation Model,
    - Hydro One will maintain the current (2022) fixed/variable revenue split from 2023 to 2027.

- Hydro One will not recalculate the rate riders to recover misallocated future tax savings in 2023. Instead, Hydro One will continue to apply current OEB-approved misallocated future tax savings rate riders to all rate classes in 2023. For the seasonal customers that are moving to the R1/R2/UR rate classes in 2023, Hydro One will continue to apply the "seasonal" rider of $1.79 per month charge in 2023. It is appropriate to continue applying the "seasonal" rider of $1.79 per month to all seasonal customers in 2023 as it represents a better alignment between these customers' contributions to the misallocated future tax savings (before the seasonal rate class was eliminated) and the recovery of the amounts from these customers.

**Approval**

| | |
|---|---|
| Parties in Support: | Anwaatin, AMPCO, CME, CCC, DRC, EP, ED, LPMA, MFN, OSEA, PP, QMA, SEC, VECC |
| Parties Opposed: | None |
| Parties Taking No Position: | CUSW, SUP, PWU, IRSS |

**Evidence**

The evidence in relation to this issue includes the following:

| | |
|---|---|
| Pre-filed Evidence | L-01-01 Introduction to Cost Allocation and Rate Design<br>L-01-02 Distribution Customer Classification<br>L-02-01 Distribution Rate Design (+ Att #1-5) |
| Evidence Update | N/A |
| Interrogatories | I-01-A-Staff-004, I-01-A-Staff-328 to Staff-332, I-01-O-Staff-392 (+Att #1), I-08-L-Energy Probe-079, I-09-L-ED-026, I-22-L-SEC-237 to SEC-239, I-22-O-SEC-252 (+Att #2-3), I-24-L-VECC-121 to VECC-125, I-24-L-VECC-129 to VECC-130, I-24-L-VECC-132, I-24-L-VECC-164 |
| Undertakings | JT-4.10, JT-4.12, JT-VECC-TCQ-21 to 23, JT-VECC-TCQ-26 |
| Pre-Settlement | SC-24-VECC-05 |
| Other | SC Day 1 Responses – C, SC Day 1 Responses – D |

*33. Are the proposed billing determinants appropriate?*

**Complete Settlement**

The Parties agree that, with the modification to the Distribution and Transmission load forecasts as described under Issue 27 above, the billing determinants resulting from the modified load forecasts (as set out under Issue 27 above) are appropriate.

**Approval**

| | |
|---|---|
| Parties in Support: | Anwaatin, AMPCO, CME, CCC, DRC, EP, LPMA, MFN, OSEA, PP, QMA, SEC, VECC |
| Parties Opposed: | None |
| Parties Taking No Position: | CUSW, SUP, ED, PWU, IRSS |

**Evidence**

The evidence in relation to this issue includes the following:

| | |
|---|---|
| Pre-filed Evidence | L-02-01 Distribution Rate Design (+ Att #1);<br>D-03-01 Hydro One Load Forecast – Key Economic and Demographic Assumptions (+ Att #1)<br>D-04-01 Transmission Load Forecast and Methodology (+ Att #1)<br>D-05-01 Distribution Load Forecast and Methodology (+Att #1 to 3) |
| Evidence Update | O-01-03 Load Forecast Update |
| Interrogatories | I-24-H-VECC-104; see also Interrogatories under Issue 27 |
| Undertakings | JT-VECC-TCQ-09_01; see also Undertakings under Issue 27 |
| Pre-Settlement | N/A |
| Other | N/A |

*34. Are the proposed revenue-to-cost ratios for all rate classes over the test period appropriate?*

**Complete Settlement**

The Parties agree that, subject to the following, the proposed revenue-to-cost ratios for all rate classes over the test period are appropriate:

- Hydro One will stop performing R/C ratio adjustments (for the purpose of ensuring all rate classes have R/C ratios that are within the OEB-approved range) in its 2024 to 2027 rate design models. For greater certainty, R/C ratio adjustments will be performed only in Hydro One's 2023 rate design model; and

- Hydro One will perform the 2023 R/C ratio adjustments in accordance with the following principles:

- to bring the R/C ratio of a rate class that is below the OEB-approved range to within the OEB-approved range by increasing the revenue requirement for this rate class, whereby this increase in revenue will be made up by decreasing the revenue collected from those classes with the highest R/C ratios above 1,[89] as required, and
- to bring the R/C ratio of a rate class that is above the OEB-approved range to within the OEB-approved range by decreasing the revenue requirement for this rate class, whereby this decrease in revenue will be made up by increasing the revenue collected from those classes with the lowest R/C ratios below 1,[90] as required.

A detailed illustrative numerical example of the proposed approach to R/C ratio adjustments is provided in Attachment 2 Schedule 4.0, 2023 Rate Design, to this settlement proposal.

**Approval**

| | |
|---|---|
| Parties in Support: | Anwaatin, AMPCO, CME, CCC, DRC, EP, LPMA, MFN, OSEA, PP, QMA, SEC, VECC |
| Parties Opposed: | None |
| Parties Taking No Position: | CUSW, SUP, ED, PWU, IRSS |

**Evidence**

The evidence in relation to this issue includes the following:

| | |
|---|---|
| Pre-filed Evidence | L-02-01 Distribution Rate Design (+ Att #1) |
| Evidence Update | N/A |
| Interrogatories | I-01-L-Staff-329 (+ Att #1), I-01-L-Staff-330, I-08-Energy Probe-079, I-24-L-VECC-123 |
| Undertakings | JT-VECC-TCQ-19 to 21 |
| Pre-Settlement | N/A |
| Other | N/A |

[89] There are multiple steps when more than one class's revenue collected need to be reduced:

- The rate class with the highest R/C ratio will be adjusted down to the next highest first;
- Then both rate classes' R/C ratio will be adjusted down until all shifted revenue amounts are balanced;
- The above 2 steps may need to be repeated with the rate class that has the next highest R/C ratio.

[90] There are multiple steps when more than one class's revenue collected need to be increased:

- The rate class with the lowest R/C ratio will be adjusted up to the next lowest first;
- Then both rate classes' R/C ratio will be adjusted up until all shifted revenue amounts are balanced;
- The above 2 steps may need to be repeated with the rate class that has the next lowest R/C ratio.

35. *Is the rate harmonization proposal for the Acquired Utilities (Norfolk, Haldimand and Woodstock) appropriate?*

**Complete Settlement**

The Parties accept the rate harmonization proposal for the Acquired Utilities. In 2014 and 2015, Hydro One Inc. acquired Norfolk Power Distribution Inc. (NPDI) (EB-2013-0196/0187/0198), Haldimand County Hydro Inc. (HCHI) (EB-2014-0244) and Woodstock Hydro Services Inc. (WHSI) (EB-2014-0213) (together, the "**Acquired Utilities**"). The distribution systems of each of the Acquired Utilities were transferred to Hydro One in the year following each acquisition. In the current Application, Hydro One has proposed to integrate the Acquired Utilities into Hydro One Distribution for rate making purposes. As set out under Issue 31, the parties have agreed that Hydro One will include UsofA 1815 asset costs and asset retirements in the direct allocation factor calculations utilized in the rate harmonization proposal.

**Approval**

| | |
|---|---|
| Parties in Support: | Anwaatin, AMPCO, CME, CCC, DRC, EP, LPMA, MFN, OSEA, PP, QMA, SEC, VECC |
| Parties Opposed: | None |
| Parties Taking No Position: | CUSW, SUP, ED, PWU, IRSS |

**Evidence**

The evidence in relation to this issue includes the following:

| | |
|---|---|
| Pre-filed Evidence | L-01-01 Introduction to Cost Allocation and Rate Design<br>L-01-02 Distribution Customer Classification<br>L-01-03 Distribution Cost Allocation (+ Att #1-3)<br>L-03-01 Benefits of Consolidation (+ Att #1-3) |
| Evidence Update | N/A |
| Interrogatories | I-01-L-Staff-307, I-01-L-Staff-321, I-01-L-Staff-327, I-01-L-Staff-334, I-06-L-CCC-044, I-22-L-SEC-233 to SEC-240, I-24-L-VECC-110, I-24-L-VECC-115, I-24-L-VECC-133 to VECC-138 |
| Undertakings | JT 4.11, JT 4.12, JT-VECC-TCQ-19 (+ Att #1), JT-VECC-TCQ-20 |
| Pre-Settlement | N/A |
| Other | N/A |

*36. Are the proposed changes in the Sub-Transmission class eligibility requirements appropriate?*

**Complete Settlement**

The Parties agree that, subject to the following, the changes in the Sub-Transmission (ST) class eligibility requirements are appropriate:

- Hydro One will track the actual costs of Hydro One-owned local transformers used to serve ST customers so that actual costs can be used to derive the ST local transformation charge in Hydro One's next cost-based rate application. These costs will be tracked as follows:
  - OM&A costs associated with Hydro One-owned ST local transformers will be estimated;
  - Capital (equipment only) costs will be tracked separately; and
  - Installation costs will be estimated using a "sampling" approach, whereby Hydro One will select a few sample projects and use the actual cost information from those projects to establish installation costs by type of transformer. Typically, these projects involve different types of work (in addition to the installation of ST transformers) and therefore Hydro One will estimate the costs associated with the installation of the ST local transformer based on actual project costs.

**Approval**

| | |
|---|---|
| Parties in Support: | Anwaatin, AMPCO, CME, CCC, DRC, EP, LPMA, MFN, OSEA, PP, QMA, SEC, VECC |
| Parties Opposed: | None |
| Parties Taking No Position: | CUSW, SUP, ED, PWU, IRSS |

**Evidence**

The evidence in relation to this issue includes the following:

| | |
|---|---|
| Pre-filed Evidence | L-02-01 Distribution Rate Design |
| Evidence Update | N/A |
| Interrogatories | I-01-L-Staff-322, I-24-L-VECC-107, I-24-L-VECC-126 to VECC-128 |
| Undertakings | JT-VECC-TCQ-15 to 17, JT-VECC-TCQ-24 to 26 |
| Pre-Settlement | SC-24-VECC-06 |
| Other | N/A |

*37. Are the proposed Retail Transmission Service Rates appropriate?*

**Complete Settlement**

The Parties agree that the proposed Retail Transmission Service Rates (RTSRs) are appropriate. The proposed RTSRs reflect the latest approved UTRs and use the latest rate class share of transmission charges, pursuant to the methodology approved by the OEB in Hydro One's prior applications.[91]

[91] Exhibit L-02-01, Section 8.3

**Approval**

| | |
|---|---|
| Parties in Support: | Anwaatin, AMPCO, CME, CCC, DRC, EP, LPMA, MFN, OSEA, PP, QMA, SEC, VECC |
| Parties Opposed: | None |
| Parties Taking No Position: | CUSW, SUP, ED, PWU, IRSS |

**Evidence**

The evidence in relation to this issue includes the following:

| | |
|---|---|
| Pre-filed Evidence | L-02-01 Distribution Rate Design (+ Att #5) |
| Evidence Update | N/A |
| Interrogatories | I-01-L-Staff-332, I-22-L-SEC-239, I-24-L-VECC-131 |
| Undertakings | N/A |
| Pre-Settlement | N/A |
| Other | N/A |

*38. Are the proposed bill impact mitigation measures appropriate?*

**Complete Settlement**

The Parties agree that the proposed bill impact mitigation measures are appropriate. The total bill impacts at typical/average consumption levels across most rate classes resulting from the proposed Distribution revenue requirement are below the OEB's 10% threshold at which bill impact mitigation measures are required. As a result, no bill impact mitigation measures are required except for in respect of seasonal customers moving to the R2 class[92] and certain unmetered load customers of the Acquired Utilities[93].

**Approval**

| | |
|---|---|
| Parties in Support: | Anwaatin, AMPCO, CME, CCC, DRC, EP, LPMA, MFN, OSEA, PP, QMA, SEC, VECC |
| Parties Opposed: | None |
| Parties Taking No Position: | CUSW, SUP, ED, PWU, IRSS |

[92] In its November 10, 2021 Decision and Order (EB-2020-0246 – Implementing the Elimination of the Seasonal Rate Class), the OEB directed Hydro One to phase-in the fixed charge for seasonal customers transitioning to the R2 class to the same all-fixed distribution charge as R2 customers over a period of 10 years in order to limit the total bill increase for affected seasonal customers to about 10% per year. A detailed description of the OEB directed bill impact mitigation for seasonal customers moving to R2 rate class is provided in the OEB's November 10, 2021 Decision and Order.

[93] A detailed description of the mitigation plan for certain unmetered load customers of the Acquired Utilities is provided in Exhibit L, Tab 6, Schedule 1, Section 2.2, page 18 of 20.

**Evidence**

The evidence in relation to this issue includes the following:

| | |
|---|---|
| Pre-filed Evidence | L-06-01 Distribution Bill Impacts and Mitigation |
| Evidence Update | N/A |
| Interrogatories | I-06-L-CCC-042, I-24-L-VECC-142 |
| Undertakings | JT-VECC-TCQ-26 |
| Pre-Settlement | N/A |
| Other | N/A |

## 14.0 OTHER CHARGES AND REVENUES

*39. Are Other Revenue forecasts for each of Transmission and Distribution appropriate?*

**Complete Settlement**

The Parties agree that, subject to the following modifications to External Revenues, Hydro One's proposed Other Revenues, for each of Transmission and Distribution, as shown in Part B, Section 9, Table 31 and Table 32, are appropriate:

- For External Revenues for each of Transmission and Distribution, Hydro One will increase the relevant amounts on a basis that is consistent with the inflationary increase that was applied to Hydro One's Cost of Sales – External Work as part of the March 31, 2022 Evidence Update; and

- For Distribution, Hydro One will also update its External Revenues to reflect the pole attachment rate, currently $34.76 per attacher, per year, per pole, as determined by the OEB in EB-2021-0302.

For Transmission, these updates represent an overall Transmission External Revenues envelope increase of 1.8% (or $3.4M) over the five-year Custom IR term, relative to Hydro One's proposed Transmission External Revenues, as shown in Part B, Section 9, Table 33.

For Distribution, these updates represent an overall Distribution External Revenues envelope decrease of 5.1% (or $12M) over the five-year Custom IR term, relative to Hydro One's proposed Distribution External Revenues, as shown in Part B, Section 9, Table 34.

The Parties also agree that Hydro One Transmission will explore the feasibility of using the land in transmission corridors for solar power generation facilities in a way that would result in net revenues for ratepayers and address all operational and safety concerns.

**Approval**

| | |
|---|---|
| Parties in Support: | Anwaatin, AMPCO, CME, CCC, DRC, EP, LPMA, MFN, OSEA, PP, QMA, SEC, VECC |
| Parties Opposed: | None |
| Parties Taking No Position: | CUSW, SUP, ED, PWU, IRSS |

**Evidence**

The evidence in relation to this issue includes the following:

| | |
|---|---|
| Pre-filed Evidence | A-03-01 Executive Summary<br>D-02-01 Transmission External Revenues (+ Att #1)<br>D-02-02 Distribution External Revenues (+ Att #1)<br>E-04-06 Common Corporate Costs OM&A – Transmission Cost of Sales – External Work<br>E-04-07 Common Corporate Costs OM&A – Distribution Cost of Sales – External Work |
| Evidence Update | O-01-05 Update on Transmission External Revenues Variance Account (+Att#1) |
| Interrogatories | I-01-D-Staff-183 to Staff-185, I-14-D-LPMA-019 to LPMA-020, I-14-O-LPMA-045, I-22-E-SEC-200, I-24-D-VECC-026 to VECC-031, I-24-D-VECC-034, I-24-O-VECC-173 to VECC-175 |
| Undertakings | JT-4.13 (+ Att #1), JTU-1.22 |
| Pre-Settlement | SC-24-VECC-01 |
| Other | SC Day 1 Responses – A, SC Day 1 Responses – C, SC Day 1 Responses – D |

*40. Are the proposed Specific Service Charges appropriate? (Distribution)*

**Complete Settlement**

The Parties agree that the proposed Specific Service Charges ("**SSCs**") are appropriate. Hydro One is not requesting any new SSCs and is maintaining its existing SSCs at the 2022 OEB-approved levels for the 2023 to 2027 period.[94] The wireline pole attachment rate set by the OEB has been updated pursuant to the OEB's decision in EB-2021-0302.

**Approval**

| | |
|---|---|
| Parties in Support: | Anwaatin, AMPCO, CME, CCC, DRC, EP, LPMA, MFN, OSEA, PP, QMA, SEC, VECC |
| Parties Opposed: | None |
| Parties Taking No Position: | CUSW, SUP, ED, PWU, IRSS |

[94] Descriptions of the SSCs that are on Hydro One's proposed OEB approved tariff schedule are included in Exhibit L-04-01, Attachment 2, and the proposed SSCs for the 2023-2027 period are provided in Exhibit L-04-01, Attachment 3.

**Evidence**

The evidence in relation to this issue includes the following:

| | |
|---|---|
| Pre-filed Evidence | L-04-01 Specific Service Charges (+Att #1-3) |
| Evidence Update | N/A |
| Interrogatories | I-01-A-Staff-004, I-24-D-VECC-032, I-24-L-VECC-139 |
| Undertakings | N/A |
| Pre-Settlement | N/A |
| Other | SC – Day 1 Responses – C |

**APPENDIX 'A' – STUDIES, REPORTS AND REPORTING**

The Parties agree that Hydro One will undertake, implement, prepare and/or provide the following, on terms set out below:

## A. REPORTING

### 1. Capital Program Performance Reports

For each of Distribution and Transmission, Hydro One will prepare a Capital Program Performance Report (similar to those which are filed in EB-2021-0110 at Exhibit B-02-01, TSP Section 2.9, Attachment 2 and at Exhibit B-03-01, DSP Section 3.9, Attachment 3). Either as part of these reports, or through separate reports, Hydro One will report on General Plant execution.

The Capital Program Performance Reports will be prepared subject to the following conditions: i) they will be prepared annually after Audited Financial Statements are published, and no earlier than April 30$^{th}$ for the previous year; ii) upon completion they will be published on Hydro One's website; iii) they will be prepared for the purposes of Hydro One's next Distribution and Transmission cost-based rate application and will not form part of Hydro One's annual update applications during the 2023-2027 Custom IR term; and iv) they may be redacted if necessary.

### 2. Scorecards

For each of Distribution and Transmission, Hydro One will prepare and publish its scorecard approved under Issue 8, subject to the following conditions: i) they will be prepared annually, no earlier than September 30$^{th}$ each year to align with OEB Reporting and Record Keeping Requirements ("**RRR**") scorecards; ii) upon completion they will be published on Hydro One's website; iii) they will be prepared for the purposes of Hydro One's next Distribution and Transmission cost-based rate application and will not form part of Hydro One's annual update applications during the 2023-2027 Custom IR term; iv) they will include discussion sections similar to the OEB Distribution RRR Scorecard; and v) they may be redacted if necessary.

### 3. DER Reporting

Hydro One Distribution will publish an update of the information in the table on page 2 of JT-3.22 in EB-2021-0110 and provide a breakdown between behind-the-meter and front-of-the-meter resources. This information will be prepared subject to the following conditions: i) it will be published on an annual basis at the time the Capital Program Performance Report for Distribution is published; ii) upon completion it will be published on Hydro One's website; and iii) it will be prepared for the purposes of Hydro One's next Distribution cost-based rate application and will not form part of Hydro One Distribution's annual update application during the 2023-2027 Custom IR term.

**4. Indigenous Reliability Reporting**

Hydro One Distribution will prepare and provide an Indigenous Reliability Report as part of its next cost-based rate application.

**5. US GAAP to IFRS Transition Impacts**

Subject to the accounting system limitations identified by Hydro One during the proceeding (A-Staff-13, A-Staff-14, A-Staff-15) and the issuance by the IASB of a final IFRS Standard applicable to rate regulated utilities, Hydro One will provide in its next cost-based rate application, on a best efforts basis and without prejudice to its submissions in future applications as to the most appropriate accounting standard to be applied to Hydro One for regulatory purposes, estimated impacts (directional, and ranges where reasonably practical) of an initial transition from USGAAP to IFRS for regulatory purposes as at the beginning of the next rate term, as well as estimated impacts on the annual revenue requirements for the remainder of the rate term. To the extent reasonably possible, the impacts will be broken down based on the areas of potential revenue requirement impacts identified in the PwC US GAAP to IFRS Conversion Impact Review Report (Exhibit A/Tab 6/Schedule 1/Attachment 1/p. 9). Hydro One will also, on a best efforts and without prejudice basis, quantify the incremental costs of transitioning and maintaining IFRS for regulatory purposes.

**6. Density Information**

In addition to updating the information provided in response to L-VECC-117, Hydro One Distribution will provide, by filing on RESS under EB-2021-0110 no later than December 31, 2022, the aggregate numbers of assets by geographic density area (low, medium and high-density) for the following types of assets:

- Poles
- Line transformers
- Overhead devices count total (the total number of switches, fuses, reclosers/sectionalizers, capacitors and voltage regulators)

**B. INDEPENDENT THIRD-PARTY STUDIES**

**1. Third-Party Studies**

The following studies shall be prepared by independent third-parties for Hydro One, and shall be filed by Hydro One in its next cost-based rate application:

a) Transmission and Distribution Total Factor Productivity and total cost econometric benchmarking studies;
b) Distribution vegetation management cost benchmarking study and an assessment of vegetation management practices;
c) Assessment of Hydro One's fleet asset strategy, management, and costs;
d) Common Corporate Costs Benchmarking Study;

e) Corporate Cost Allocation Review;
f) Compensation Benchmarking Study using similar/same methodology as the current Mercer report;[95]
g) Management and Non-Represented Role Benchmarking and Compensation Study using same/similar methodology as Willis Towers Watson report;[96]
h) Actuarial Pension Valuation for Hydro One's defined benefit pension plan;
i) Projected Benefit Costs for its Pension Plans and Post-Employment Benefit Plans; and
j) Depreciation Study, which for greater certainty will be conducted based on the most recent actuals available at the relevant time. As such, it will only be conducted based on existing assets and not future assets. Therefore, to the extent that the regulated Transmission or Distribution businesses have DER assets, those assets will be included in the study. On a best-efforts basis, as part of the next study, Hydro One will request that the third-party depreciation expert develop useful lives for DERs to the extent that Hydro One is able to provide asset information for those assets.

## C. PLANNING

### 1. Long-Term Capital Plan Information

At its next cost-based rate application, Hydro One will provide a summary of long-term (10-20 years) forecast information for Hydro One Transmission and Distribution that is available in Regional Planning Reports and IESO Bulk planning. The information will be consistent with the framework being developed by the Regional Planning Process Advisory Group ("**RPPAG**"). The Parties acknowledge that this would represent a comprehensive long-term plan since it will incorporate the areas of regional planning that Hydro One is responsible for, the distribution components that are reflected within the regional plans, and the IESO's Bulk plan (which is the sole responsibility of the IESO).

### 2. Electrification Planning

As part of its next cost-based rate application, Hydro One Distribution will arrange for a study to be prepared by an independent consultant to examine general electrification scenarios for the 2030-2050 timeframe. The study will provide the directional distribution needs and recommendations for potential cost-effective solutions for electrification to minimize unit distribution costs. The consultant will invite input from the intervenors in EB-2021-0110. This study will not be a substitute for the Regional Planning process, and the specific facilities required for electrification in each Region / LDC territory will continue to be identified as part of the Regional Planning process.

**3.** For greater certainty, the words "recommendations for potential cost-effective solutions for electrification" in the above paragraph is not meant to be narrow such that it necessarily excludes

[95] Provided in Exhibit E-06-01 Attachment 1.
[96] Provided in Undertaking JT-4.27.

consideration in the study of (a) how to size equipment to ensure it can handle potential electrification scenarios without replacement before end-of-life; (b) how to use electrification to flatten the overall load profile, improve the load factor and increase revenue to lower unit costs; (c) how to time system upgrades to match demand increases and revenue therefrom; (d) whether/how to encourage/incent efficient use of the distribution system by EVs; (e) whether/how to encourage/incent customers to utilize smart switches to "share" circuit breakers and thus avoid panel upgrades; or (f) other similar topic areas.

**4. Non-Wires Solutions – Planning Process**

Hydro One Distribution will develop and implement a robust planning process that appropriately considers non-wires solutions ("**NWSs**"), including CDM, to meet system service needs, which (a) includes capital and O&M cost assumptions for NWSs, (b) requires examination of NWSs in a timely fashion such that alternatives are not dismissed simply because of lack of time, and (c) includes appropriate stakeholder engagement.

Hydro One Distribution will leverage its existing procurement processes in respect of projects greater than a $5M threshold. Distribution projects will be considered for NWSs in accordance with the most recent CDM guideline, subject to a $5M threshold. This will apply on a best-efforts basis only, beginning with projects planned to commence construction in 2025. This is because the development and implementation of a robust planning process, that appropriately considers NWSs, including CDM, to meet system service needs must be developed, tested and proven to be effective and Hydro One Distribution has no experience in doing so. Once developed, tested and proven to be effective, Hydro One Distribution will apply the process in the ordinary course.

**5. Municipal Energy Plans**

Hydro One will meaningfully consider the goals of municipal energy and emission plans with a view to pursuing cost efficiencies, reduced emissions, and enhanced energy outcomes for consumers in Ontario served by Hydro One. Hydro One will include these elements in its next Transmission and Distribution System Plans, and the supporting Business Plan, where relevant and feasible.

**6. Climate Change and Investment Planning**

Hydro One will include, in future operational and capital investments plans, discussion of how the proposed spending will directly support the achievement of Hydro One's climate change policy commitments by 2030 and 2050.

**7. Non-Wires Alternative Solutions – Bi-Directional Charger Study**

Hydro One Distribution, as part of its next Distribution cost-based rate application, will provide a summary of the bi-directional charger pilot program engagement,[97] results and, if possible, viable use cases.

**8. Capacity Restrictions for DERs**

Hydro One will review and assess options to mitigate capacity restrictions on its Distribution system and will recommend next steps (if any) to be considered for its next DSP and TSP (or sooner for any next steps that do not have significant costs, can be accommodated within existing funding envelopes, or can be funded through other means).

## D. LINE LOSSES

**1. Updated Distribution Line Loss Study**

Hydro One Distribution will conduct an analysis of its overall distribution losses, similar to what it filed in EB-2017-0049. Should Hydro One observe a material change in overall losses, Hydro One will conduct a detailed distribution line loss study.

**2. Transmission System Line Loss Guideline Update**

Hydro One Transmission will continue participating in the IESO's transmission losses engagement process. Within six months of the final IESO guideline being published as part of the IESO stakeholder process, Hydro One will review and, if necessary, update its transmission line loss guideline.

**3. Distribution System Electricity Losses**

Hydro One Distribution will prepare a review of utility practices for mitigating distribution system losses. The review will consider best practices of other distributors (where applicable) and provide recommendations (if any) to cost-effectively reduce losses, including details on when and how those recommendations would be implemented. The review will be provided part of Hydro One’s next distribution cost-based rate application and Hydro One will include information discussing its response to any recommendations.

**4. Loss Studies for Projects Not Requiring Leave to Construct**

Hydro One Distribution will review relevant planning standards to confirm that they will capture all cost-effective opportunities to reduce line losses when replacing infrastructure.

Hydro One Transmission will prepare line loss assessments for material investments that do not require a leave to construct application and include such assessments in its TSP ISDs according to

[97] See Interrogatory B3-ED-028 part d): the pilot project with Peak Power and the IESO.

Hydro One's Transmission line loss guideline at the design phase of the project. The assessments will be filed as part of Hydro One Transmission's next cost-based rate application.

## E. SPECIFIC PROGRAM REQUIREMENT

**1. Energy Storage – Grid Scale (D-SS-04)**

Hydro One Distribution shall undertake competitive procurement processes for reliability services from energy storage solution providers for projects over the 2025-2027 period and, in this regard, shall actively seek economic participation or equity investment opportunities from First Nations as part of its standard procurement practice. The terms of the procurements shall not prevent third parties from lowering the cost to Hydro One by participating in the IESO-administered markets (e.g., real-time price arbitrage, capacity services, ancillary services, etc.) as long as that participation would not unduly detract from the reliability services to Hydro One customers (i.e. the market participation could reduce the reliability benefits only by a small degree). Furthermore, Hydro One will record in a new variance account any variances in accounting treatment resulting from any third-party ownership, with disposition to be determined in the next rebasing.

**2. Energy Storage – Residential (D-SS-04)**

Hydro One confirms that the purpose of the Energy Storage – Residential (D-SS-04) investment is to improve reliability at the lowest cost to ratepayers. Parties agree that the agreement to the 2023-2027 system service capital expenditures and in-service-additions shall not be construed as the Intervenor Parties necessarily agreeing that it is appropriate for Hydro One to own and operate behind-the-meter assets.

The Framework for Energy Innovation consultation (EB-2021-0118) is expected to provide regulatory clarity on the treatment of innovative technologies, including the use of third-party DERs to provide reliability improvements. Following regulatory clarity from the OEB, if there is a reputable third-party aggregator for residential battery storage units in Ontario that enables improved reliability, and that third-party aggregator expresses an interest in providing this service on reasonable terms and conditions and appropriate scale to Hydro One, then Hydro One will consider this and, if appropriate, will leverage Hydro One's existing procurement processes. In the event that this does arise, and the units are used to participate in the IESO administered markets, Hydro One will record in a new deferral account, to the benefit of ratepayers, any net revenue derived by Hydro One from the third-party's participation in the IESO administered markets, with disposition to be determined in the next rebasing.

**3. Energy Storage – Reporting (D-SS-04)**

Hydro One Distribution will prepare, and file as part of its next Distribution cost-based rate application, a baseline reliability assessment for the target customers and communities to assess the success in achieving the expected outages. The assessment will include:

- Outage frequency on a monthly basis over an historical 3-year period; and
- Outage duration on a monthly basis over an historical 3-year period.

For Grid Scale energy storage, Hydro One will provide performance data on an annual basis such as number and duration of outages experienced as well as availability of the BESS system. For residential storage, Hydro One will require the vendor's solution to be able to provide performance data on an annual basis, and Hydro One will provide the vendor's performance data on an annual basis.

The performance data will be published on the Hydro One website at the time the Capital Performance Report is published. The performance data are prepared for the purposes of Hydro One's future cost-based rate applications and will not form part of Hydro One Distribution's annual update application during the 2023-2027 Custom IR term.

**4. Explore Value from Right-of-Ways**

Hydro One Transmission will explore the feasibility of using the land in transmission corridors for solar power generation facilities in a way that would result in net revenues for ratepayers and address all operational and safety concerns.

**F. OTHER**

**1. Electronic Billing**

During the course of this proceeding parties became aware that Hydro One had implemented a program to transition paper billed customers to e-billing where customers had provided Hydro One with an email address during a prior transaction.. Hydro One confirmed that it had implemented an electronic billing ("e-billing") pilot program which had since ended. Its current and standard process for transitioning customers from paper billing to electronic billing is as follows:

Step 1: Customers on paper billing receive a paper insert with their bill advising them that they will be moved to e-billing. The insert includes the following language that describes how to remain on paper-billing: "We respect your preferences. If you don't want a paperless bill, you can switch back to paper billing at any time. Change your preferences by logging into HydroOne.com/KeepPaper".

Step 2: Seven to 10 days prior to their first e-bill, customers receive an email reminding them that they are being switched over to e-billing. It also includes the above language describing how to remain on paper-billing.

Step 3: If the customer does not pay their first e-bill, Hydro One automatically un-enrolls them from e-billing and places them back on paper billing, and no late payment charges or other penalties are incurred.

While the standard procedure does transition customers without their explicit consent it also assumes that any transition customer who fails to pay their first e-bill has declined to continue with this service and thereby reverts to the former paper billing option and without penalty. The "non-payment return to paper" element was also part of the pilot program. The standard process differed from the pilot in that, for the standard process, Hydro One sends a notice to the customer advising them that they have been enrolled in e-billing, explains that e-billing is optional and provides the customer with instructions on how to decline e-billing using a simple and convenient method. The pilot was different in that it did not include language stating that e-billing was optional and did not include a description of the process to decline e-billing.

The Parties agree that to address concerns arising from the e-billing pilot program, Hydro One will take the following steps:

1) it will not charge for providing paper bills;
2) it will contact every customer who was contacted as part of the pilot and inform them that they are not required to be on e-billing and may return to paper bill at no cost;
3) it will reverse (return) any late payment charge to a customer who incurred such a charge after being converted to e-billing as part of the pilot;
4) it will confirm with any customer who was converted to e-billing and who wishes to remain on e-billing after (2) that the email provided is the correct one to use;
5) it will ensure that no customer who has switched to e-billing as part of the pilot is reported to credit agencies based on late payments; and
6) if a customer who has been auto-enrolled on e-billing does not pay their first e-bill, Hydro One will continue its practice of automatically un-enrolling that customer from e-billing and will place the customer back on paper billing without penalty or charge.

# ATTACHMENT 1 – TRANSMISSION SUPPORTING SCHEDULES

**Schedule 1.0 – Transmission Revenue Requirement Summary**

Schedule 1.1 – OM&A
Schedule 1.2 – Rate Base and Depreciation
Schedule 1.2.1 – Statement of Utility Rate Base
Schedule 1.2.2 – Continuity of PP&E (Gross Balances)
Schedule 1.2.3 – Continuity of PP&E (Accumulated Depreciation)
Schedule 1.2.4 – Appendix 2-BA Continuity Schedule (excel only) Schedule 1.3 – Capital Expenditures Schedule 1.4 – Capital Structure and Return on Capital
Schedule 1.4.1 – 2023 Cost of Long-Term Debt Capital
Schedule 1.5 – Income Tax
Schedule 1.5.1 – Calculation of Utility Income Taxes
Schedule 1.5.2 – Calculation of Capital Cost Allowance (CCA)
Schedule 1.6 – External Revenue
Schedule 1.7 – Export Transmission Service Revenue
Schedule 1.8 – Deferral and Variance Account Balances
Schedule 1.9 – Working Capital Adjustment
Schedule 1.10 – In-Service Additions

**Schedule 2.0 – Transmission Cost Allocation and Rate Design**

Schedule 2.1 – Charge determinants by rate pool
Schedule 2.2 – Rates Revenue Requirement by rate pool
Schedule 2.3 – Current UTR Schedule
Schedule 2.3.1 – Revenue Requirement and Disbursement Allocators
Schedule 2.3.2 – UTR Rate Schedule
Schedule 2.4 – Proposed UTR Schedule
Schedule 2.4.1 – Revenue Requirement and Disbursement Allocators
Schedule 2.4.2 – UTR Rate Schedule
Schedule 2.5 – Low Voltage Switchgear Credit calculations
Schedule 2.6 – Bill Impacts and Impacts on Hydro One Residential and General Service Energy Customers
Schedule 2.7 – Wholesale Meter Service and Exit Fee Schedule

## ATTACHMENT 2 – DISTRIBUTION SUPPORTING SCHEDULES

**Schedule 1.0 – Distribution Revenue Requirement Summary**

- Schedule 1.1 – OM&A
- Schedule 1.2 – Rate Base and Depreciation
  - Schedule 1.2.1 – Statement of Utility Rate Base
  - Schedule 1.2.2 – Continuity of PP&E (Gross Balances)
  - Schedule 1.2.3 – Continuity of PP&E (Accumulated Depreciation)
  - Schedule 1.2.4 – Appendix 2-BA Continuity Schedule (excel only)
- Schedule 1.3 – Capital Expenditures
- Schedule 1.4 – Capital Structure and Return on Capital
  - Schedule 1.4.1 – 2023 Cost of Long-Term Debt Capital
- Schedule 1.5 – Income Tax
  - Schedule 1.5.1 – Calculation of Utility Income Taxes
  - Schedule 1.5.2 – Calculation of Capital Cost Allowance (CCA)
- Schedule 1.6 – External Revenue
- Schedule 1.7 – Working Capital Adjustment
- Schedule 1.8 – Deferral and Variance Account Balances
- Schedule 1.9 – In-Service Additions

**Schedule 2.0 – Distribution Load Forecast**

**Schedule 3.0 – Distribution Cost Allocation**

- Schedule 3.0 - Distribution Cost Allocation Model Input and Output
- Schedule 3.1 – Cost Allocation Model

**Schedule 4.0 – Distribution Rate Design**

- Schedule 4.0 – 2023-2027 Rate Design
- Schedule 4.1 – 2023-2027 Sub-Transmission (ST) Rates
- Schedule 4.2 – RRWF for Move to All-Fixed Residential Dx Rates
- Schedule 4.3 – CSTA and Hopper Foundry Rate Adder
- Schedule 4.4 – 2023 Revenue Reconciliation

**Schedule 5.0 – Retail Transmission Service Rates**

**Schedule 6.0 – Distribution Deferral and Variance Account Disposition Riders**

Schedule 6.0 – DVA Group 1
Schedule 6.1 – DVA Group 2
Schedule 6.2 – Rate Rider Norfolk and Woodstock's 1595 Accounts
Schedule 6.3 – Rate Rider Norfolk, Haldimand and Woodstock's 1592 Accounts

**Schedule 7.0 – Distribution Bill Impacts**

Schedule 7.0 – Bill Impacts 2023 Overview
Schedule 7.1 – Bill Impacts 2023
Schedule 7.2 – Combined Bill Impacts
Schedule 7.3 – Combined Bill Impacts of Changes in Transmission and Distribution Revenue Requirements
Schedule 7.4 – Changes in base distribution rates

**Schedule 8.0 – Distribution Tariff Schedules**

Schedule 8.0 – Current Tariff Schedule – Hydro One Distribution
Schedule 8.1 – Current Tariff Schedules – Acquired LDCs
Schedule 8.2 – Proposed Tariff Schedules

## ATTACHMENT 3 – ACCOUNTING ORDERS

### SCHEDULE 1.0 – DRAFT TRANSMISSION ACCOUNTING ORDERS

Schedule 1.1 – Transmission Capitalized Overheads Tax Variance Account (new)
Schedule 1.2 – Externally Driven Transmission Projects Variance Account (new)
Schedule 1.3 – Transmission Rights Payments Variance Account (modified)
Schedule 1.4 – Transmission Sale of Properties Deferral Account (new)
Schedule 1.5 – Transmission Clean Energy Tax Credit Deferral Account (new)
Schedule 1.6 – Pension/OPEB Forecast Accrual Versus Actual Cash Payment Differential Account (modified)

### Schedule 2.0 – Draft Distribution Accounting Orders

Schedule 2.1 – Distribution Capitalized Overheads Tax Variance Account (new)
Schedule 2.2 – Externally Driven Distribution Projects Variance Account (new)
Schedule 2.3 – Distribution Connection Cost Agreement (CCA) Variance Account (new)
Schedule 2.4 – AMI 2.0 Variance Account (new)
Schedule 2.5 – Distribution Depreciation Expense (Asset Removal Costs) Asymmetrical Cumulative Variance Account (new)
Schedule 2.6 – Distribution Sale of Properties Deferral Account (new)
Schedule 2.7 – Distribution Clean Energy Tax Credit Deferral Account (new)
Schedule 2.8 – Distribution System Energy Storage – Grid Scale Accounting Treatment Variance Account (new)
Schedule 2.9 – Distribution System Energy Storage – Residential Deferral Account (new)
Schedule 2.10 – Pension/OPEB Forecast Accrual Versus Actual Cash Payment Differential Account (modified)

# ATTACHMENT 1

## TRANSMISSION SUPPORTING SCHEDULES

**Hydro One Networks Inc.**
**Implementation of Decision in EB-2021-0110**

**Revenue Requirement Summary - Transmission**

| *($ millions)* | Supporting Reference | Hydro One Proposed 2023 | Hydro One Proposed 2024 | Hydro One Proposed 2025 | Hydro One Proposed 2026 | Hydro One Proposed 2027 | OEB Decision Impact 2023 | OEB Decision Impact 2024 | OEB Decision Impact 2025 | OEB Decision Impact 2026 | OEB Decision Impact 2027 | OEB Approved 2023 | OEB Approved 2024 | OEB Approved 2025 | OEB Approved 2026 | OEB Approved 2027 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| OM&A | Exhibit 1.1 | 450.2 | 459.2 | 468.4 | 477.8 | 487.3 | (15.9) | (16.8) | (17.8) | (18.9) | (19.9) | 434.4 | 442.4 | 450.6 | 458.9 | 467.4 |
| Depreciation | Exhibit 1.2 | 531.9 | 562.7 | 601.0 | 634.3 | 658.0 | (0.6) | (4.0) | (9.5) | (20.1) | (23.2) | 531.3 | 558.7 | 591.5 | 614.1 | 634.8 |
| Return on Debt | Exhibit 1.4 | 340.0 | 361.0 | 385.9 | 409.6 | 431.2 | (1.8) | (4.1) | (7.4) | (10.6) | (13.9) | 338.1 | 356.9 | 378.5 | 398.9 | 417.4 |
| Return on Equity | Exhibit 1.4 | 487.4 | 517.6 | 553.3 | 587.2 | 618.3 | (2.6) | (5.8) | (10.5) | (15.2) | (19.8) | 484.9 | 511.8 | 542.8 | 572.1 | 598.5 |
| Working Capital Adjustment | Exhibit 1.9 | | (0.1) | (0.0) | (0.1) | (0.0) | | (0.0) | (0.0) | (0.0) | (0.0) | | (0.1) | (0.0) | (0.1) | (0.0) |
| Productivity Factor | | | (2.3) | (4.7) | (7.2) | (9.9) | | (3.0) | (6.1) | (9.4) | (12.8) | | (5.2) | (10.8) | (16.6) | (22.7) |
| RCI Annual Update | | | | | | | | | | | | | | | | |
| Regulatory Tax | Exhibit 1.5 | 39.8 | 70.0 | 59.1 | 80.9 | 81.7 | 4.0 | 4.3 | 6.5 | 3.5 | 4.5 | 43.8 | 74.2 | 65.6 | 84.4 | 86.3 |
| **Base Revenue Requirement** | | **1,849.3** | **1,968.2** | **2,063.0** | **2,182.5** | **2,266.6** | **(16.8)** | **(29.5)** | **(44.8)** | **(70.7)** | **(85.1)** | **1,832.5** | **1,938.7** | **2,018.2** | **2,111.8** | **2,181.6** |
| Deduct: External Revenue | Exhibit 1.6 | (40.1) | (36.2) | (36.5) | (36.2) | (37.3) | (0.7) | (0.7) | (0.6) | (0.7) | (0.7) | (40.8) | (36.9) | (37.1) | (36.9) | (37.9) |
| **Subtotal** | | **1,809.2** | **1,932.0** | **2,026.6** | **2,146.3** | **2,229.4** | **(17.5)** | **(30.1)** | **(45.5)** | **(71.3)** | **(85.7)** | **1,791.6** | **1,901.8** | **1,981.1** | **2,074.9** | **2,143.6** |
| Deduct: Export Service Credit | Exhibit 1.7 | (37.4) | (37.1) | (37.3) | (37.2) | (37.2) | | | | | | (37.4) | (37.1) | (37.3) | (37.2) | (37.2) |
| Add: Other Cost Charges (DVA Balances) | Exhibit 1.8 | (26.4) | 1.1 | 1.1 | 1.1 | 1.1 | 3.9 | (1.1) | (1.1) | (1.1) | (1.1) | (22.5) | | | | |
| Add: Low Voltage Switch Gear | | 16.5 | 17.5 | 18.2 | 19.2 | 19.8 | (0.2) | (0.1) | 0.1 | 0.0 | (0.1) | 16.3 | 17.4 | 18.3 | 19.3 | 19.8 |
| Deduct: MSP Revenue | | (0.0) | (0.0) | | | | | | | | | (0.0) | (0.0) | | | |
| **Rates Revenue Requirement** | | **1,761.9** | **1,913.5** | **2,008.6** | **2,129.3** | **2,213.1** | **(13.9)** | **(31.3)** | **(46.5)** | **(72.4)** | **(86.9)** | **1,748.0** | **1,882.1** | **1,962.1** | **2,056.9** | **2,126.2** |

**Hydro One Networks Inc.**
**Implementation of Decision in EB-2021-0110**

**Transmission OM&A**

| ($ millions) | Supporting Reference | Hydro One Proposed | | | | | OEB Decision Impact | | | | | OEB Approved | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | 2023 | 2024 | 2025 | 2026 | 2027 | 2023 | 2024 | 2025 | 2026 | 2027 | 2023 | 2024 | 2025 | 2026 | 2027 |
| OM&A | Exhibit O-01-02, Table 3 | 442.6 | 451.5 | 460.5 | 469.7 | 479.1 | (8.2) | (9.1) | (9.9) | (10.8) | (11.7) | 434.4 | 442.4 | 450.6 | 458.9 | 467.4 |
| Proposed PCB Treatment | | 7.6 | 7.8 | 7.9 | 8.1 | 8.2 | (7.6) | (7.8) | (7.9) | (8.1) | (8.2) | - | - | - | - | - |
| Total OM&A [1] | | 450.2 | 459.2 | 468.4 | 477.8 | 487.3 | (15.9) | (16.8) | (17.8) | (18.9) | (19.9) | 434.4 | 442.4 | 450.6 | 458.9 | 467.4 |

*OEB Decision Impact Supporting Details*

| **Adjustments** | **Settlement Proposal Reference** | **2023** |
|---|---|---|
| PCB Shift from OM&A to Dep. | Part C, Issue 22 | (7.6) |
| 2% OMA Cut [2] | Part C, Issue 18 | (8.9) |
| OH Cap impact from Capex reduction | Part C, Issue 16 | 0.6 |
| **Total Adjustments** | | **(15.9)** |

Note [1]: The Total OM&A line includes the Proposed PCB Treatment for revenue requirement purposes as proposed by Hydro One
Note [2]: 2% OM&A reduction is applied on the $442.6M figure

**Hydro One Networks Inc.**
**Implementation of Decision in EB-2021-0110**

**Transmission Rate Base and Depreciation**

| | | Hydro One Proposed | | | | | OEB Decision Impact | | | | | OEB Approved | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| *($ millions)* | **Supporting Reference** | **2023** | **2024** | **2025** | **2026** | **2027** | **2023** | **2024** | **2025** | **2026** | **2027** | **2023** | **2024** | **2025** | **2026** | **2027** |
| Rate Base | See supporting details below | 14,611.5 | 15,516.6 | 16,585.5 | 17,602.6 | 18,534.1 | (77.1) | (174.2) | (314.5) | (454.1) | (594.0) | 14,534.4 | 15,342.4 | 16,271.0 | 17,148.5 | 17,940.2 |
| | Exhibit E-08-01, Attachment 2 | 539.5 | 570.2 | 607.6 | 634.3 | 658.0 | (8.2) | (11.5) | (16.1) | (20.1) | (23.2) | 531.3 | 558.7 | 591.5 | 614.1 | 634.8 |
| Depreciation [1] | Exhibit D-01-01 | (7.6) | (7.5) | (6.6) | - | - | 7.6 | 7.5 | 6.6 | - | - | - | - | - | - | - |
| | Exhibit O-01-02, Attachment 8 | 531.9 | 562.7 | 601.0 | 634.3 | 658.0 | (0.6) | (4.0) | (9.5) | (20.1) | (23.2) | 531.3 | 558.7 | 591.5 | 614.1 | 634.8 |

Note [1] The Depreciation line reflected the Proposed PCB Treatment for revenue requirement purposes, as further explained in Section 4 of Exhibit D-01-01

*OEB Decision Impact Supporting Details*

**Detailed Calculation**

Working Capital Adjustment

| | 2023 | 2024 | 2025 | 2026 | 2027 | 2023 | 2024 | 2025 | 2026 | 2027 | 2023 | 2024 | 2025 | 2026 | 2027 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Rate Base Details | | | | | | | | | | | | | | | |
| Utility plant (average) | | | | | | | | | | | | | | | |
| Gross plant at cost | 22,930.8 | 24,263.5 | 25,789.7 | 27,294.4 | 28,750.8 | (70.1) | (169.9) | (316.3) | (465.6) | (618.6) | 22,860.7 | 24,093.6 | 25,473.4 | 26,828.8 | 28,132.1 |
| Less: Accumulated depreciation | (8,352.1) | (8,781.6) | (9,238.8) | (9,727.6) | (10,252.7) | (5.5) | (2.8) | 3.2 | 12.9 | 26.0 | (8,357.6) | (8,784.3) | (9,235.5) | (9,714.7) | (10,226.7) |
| Add: CWIP | | | | | | | | | | | - | - | - | - | - |
| Net utility plant | 14,578.7 | 15,481.9 | 16,551.0 | 17,566.8 | 18,498.0 | (75.6) | (172.6) | (313.0) | (452.7) | (592.6) | 14,503.1 | 15,309.3 | 16,237.9 | 17,114.1 | 17,905.4 |
| Working capital | | | | | | | | | | | | | | | |
| Cash working capital | 18.7 | 20.3 | 19.8 | 20.8 | 20.8 | (1.6) | (1.5) | (1.4) | (1.4) | (1.3) | 17.2 | 18.7 | 18.4 | 19.4 | 19.5 |
| Materials & supplies inventory | 14.1 | 14.4 | 14.7 | 15.0 | 15.3 | | | | | | 14.1 | 14.4 | 14.7 | 15.0 | 15.3 |
| Total working capital | 32.9 | 34.7 | 34.5 | 35.8 | 36.1 | (1.6) | (1.5) | (1.4) | (1.4) | (1.3) | 31.3 | 33.1 | 33.1 | 34.4 | 34.8 |
| Total Rate Base | 14,611.5 | 15,516.6 | 16,585.5 | 17,602.6 | 18,534.1 | (77.1) | (174.2) | (314.5) | (454.1) | (594.0) | 14,534.4 | 15,342.4 | 16,271.0 | 17,148.5 | 17,940.2 |

**HYDRO ONE NETWORKS INC.**
**TRANSMISSION**
**Statement of Utility Rate Base**
Historical Year (2021), Bridge Year (2022) and Test Years (2023 to 2027)
Year Ending December 31
($M)

| **Particulars** | **2021** | **2022** | **2023** | **2024** | **2025** | **2026** | **2027** |
|---|---|---|---|---|---|---|---|
| Electric Utility Plant | | | | | | | |
| Gross plant at cost | $ 20,898.3 | $ 22,227.2 | $ 23,494.2 | 24,693.0 | $ 26,253.9 | $ 27,403.7 | $ 28,860.6 |
| Less: accumulated depreciation | $ (7,743.7) | $ (8,151.1) | (8,564.1) | (9,004.6) | (9,466.5) | (9,963.0) | (10,490.5) |
| Net plant for rate base | $ 13,154.6 | $ 14,076.1 | 14,930.1 | 15,688.4 | 16,787.4 | 17,440.7 | 18,370.0 |
| Average net plant for rate base | | | 14,503.1 | 15,309.3 | 16,237.9 | 17,114.1 | 17,905.4 |
| Average net utility plant | | | $ 14,503.1 | $ 15,309.3 | $ 16,237.9 | $ 17,114.1 | $ 17,905.4 |
| Working Capital | | | | | | | |
| Cash working capital | | | 17.2 | 18.7 | 18.4 | 19.4 | 19.5 |
| Materials and Supplies Inventory | | | 14.1 | 14.4 | 14.7 | 15.0 | 15.3 |
| Total working capital | | | 31.3 | 33.1 | 33.1 | 34.4 | 34.8 |
| Total rate base | | | $ 14,534.4 | $ 15,342.4 | $ 16,271.0 | $ 17,148.5 | $ 17,940.2 |

**HYDRO ONE NETWORKS INC.**
**TRANSMISSION**
Continuity of Property, Plant and Equipment
Historical (2021), Bridge (2022) & Test (2023-2027) Years
Year Ending December 31
Total - Gross Balances
($M)

| Line No. | Year | Opening Balance | Additions | Retirements | Sales | Transfers In/Out | Closing Balance | Average |
|---|---|---|---|---|---|---|---|---|
| | | (a) | (b) | (c) | (d) | (e) | (f) | (g) |
| Historical | | | | | | | | |
| 1 | 2021 | 19,969.4 | 997.3 | (32.1) | (9.4) | (26.9) | 20,898.3 | 20,433.9 |
| Bridge | | | | | | | | |
| 2 | 2022 | 20,898.3 | 1381.6 | (53.8) | | 1.0 | 22,227.2 | 21,562.8 |
| Test | | | | | | | | |
| 3 | 2023 | 22,227.2 | 1334.1 | (68.1) | | 1.0 | 23,494.2 | 22,860.7 |
| 4 | 2024 | 23,494.2 | 1264.2 | (66.4) | | 1.0 | 24,693.0 | 24,093.6 |
| 5 | 2025 | 24,693.0 | 1631.8 | (72.0) | | 1.1 | 26,253.9 | 25,473.5 |
| 6 | 2026 | 26,253.9 | 1212.7 | (63.9) | | 1.1 | 27,403.7 | 26,828.8 |
| 7 | 2027 | 27,403.7 | 1512.5 | (56.8) | | 1.1 | 28,860.6 | 28,132.1 |

**HYDRO ONE NETWORKS INC.**
**TRANSMISSION**
Continuity of Property, Plant and Equipment - Accumulated Depreciation
Historical (2021), Bridge (2022) & Test (2023-2027) Years
Year Ending December 31
Total - Gross Balances
($M)

| Line No. | Year | Opening Balance | Additions | Retirements | Sales | Transfers In/Out and Other | Closing Balance | Average |
|---|---|---|---|---|---|---|---|---|
| | | (a) | (b) | (c) | (d) | (e) | (f) | (g) |
| Historical | | | | | | | | |
| 1 | 2021 | 7,348.6 | 430.6 | (32.1) | (3.4) | 0.1 | 7,743.7 | 7,546.1 |
| Bridge | | | | | | | | |
| 2 | 2022 | 7,743.7 | 461.2 | (53.8) | | | 8,151.1 | 7,947.4 |
| Test | | | | | | | | |
| 3 | 2023 | 8,151.1 | 481.1 | (68.1) | | | 8,564.1 | 8,357.6 |
| 4 | 2024 | 8,564.1 | 506.9 | (66.4) | | | 9,004.6 | 8,784.3 |
| 5 | 2025 | 9,004.6 | 533.9 | (72.0) | | | 9,466.5 | 9,235.5 |
| 6 | 2026 | 9,466.5 | 560.4 | (63.9) | | | 9,963.0 | 9,714.7 |
| 7 | 2027 | 9,963.0 | 584.3 | (56.8) | | | 10,490.5 | 10,226.7 |

# APPENDIX 2-BA CONTINUITY SCHEDULE

This schedule has been filed separately in MS Excel format.

**Hydro One Networks Inc.**
**Implementation of Decision in EB-2021-0110**

**Transmission Capital Expenditures**

| *($ millions)* | Supporting Reference | Hydro One Proposed | | | | | OEB Decision Impact | | | | | OEB Approved | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | 2023 | 2024 | 2025 | 2026 | 2027 | 2023 | 2024 | 2025 | 2026 | 2027 | 2023 | 2024 | 2025 | 2026 | 2027 |
| Capital expenditures | Exhibit O-01-02, Attachment 4A | 1,509.3 | 1,540.7 | 1,526.6 | 1,538.5 | 1,524.3 | (147.2) | (151.3) | (153.3) | (156.4) | (154.1) | 1,362.1 | 1,389.4 | 1,373.3 | 1,382.1 | 1,370.2 |

OEB Decision Impact Supporting Details

| **Adjustments** | **Settlement Proposal Reference** | **2023** | **2024** | **2025** | **2026** | **2027** |
|---|---|---|---|---|---|---|
| Overall capital reduction | Part C, Issue 9 | (147.2) | (151.3) | (153.3) | (156.4) | (154.1) |
| | | (147.2) | (151.3) | (153.3) | (156.4) | (154.1) |

**Hydro One Networks Inc.**
**Implementation of Decision in EB-2021-0110**

**Transmission Capital Structure and Return on Capital**

| | Hydro One Proposed | | | | | OEB Decision Impact | | | | | OEB Approved | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| *($ millions)* | **2023** | **2024** | **2025** | **2026** | **2027** | **2023** | **2024** | **2025** | **2026** | **2027** | **2023** | **2024** | **2025** | **2026** | **2027** |
| **Return on Rate Base** | | | | | | | | | | | | | | | |
| Rate Base | $ 14,611.5 | $ 15,516.6 | $ 16,585.5 | $ 17,602.6 | $ 18,534.1 | $ (77.1) | $ (174.2) | $ (314.5) | $ (454.1) | $ (594.0) | $ 14,534.4 | $ 15,342.4 | $ 16,271.0 | $ 17,148.5 | $ 17,940.2 |
| Capital Structure: | | | | | | | | | | | | | | | |
| Third-Party long-term debt | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| Deemed long-term debt | 56.0% | 56.0% | 56.0% | 56.0% | 56.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 56.0% | 56.0% | 56.0% | 56.0% | 56.0% |
| Short-term debt | 4.0% | 4.0% | 4.0% | 4.0% | 4.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 4.0% | 4.0% | 4.0% | 4.0% | 4.0% |
| Common equity | 40.0% | 40.0% | 40.0% | 40.0% | 40.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 40.0% | 40.0% | 40.0% | 40.0% | 40.0% |
| Capital Structure: | | | | | | | | | | | | | | | |
| Third-Party long-term debt | | | | | | | | | | | | | | | |
| Deemed long-term debt | $ 8,182.5 | $ 8,689.3 | $ 9,287.9 | $ 9,857.5 | $ 10,379.1 | (43.2) | (97.5) | (176.1) | (254.3) | (332.6) | $ 8,139.3 | $ 8,591.7 | $ 9,111.8 | $ 9,603.1 | $ 10,046.5 |
| Short-term debt | 584.5 | 620.7 | 663.4 | 704.1 | 741.4 | (3.1) | (7.0) | (12.6) | (18.2) | (23.8) | 581.4 | 613.7 | 650.8 | 685.9 | 717.6 |
| Common equity | 5,844.6 | 6,206.6 | 6,634.2 | 7,041.0 | 7,413.7 | (30.9) | (69.7) | (125.8) | (181.7) | (237.6) | 5,813.8 | 6,137.0 | 6,508.4 | 6,859.4 | 7,176.1 |
| | **$ 14,611.5** | **$ 15,516.6** | **$ 16,585.5** | **$ 17,602.6** | **$ 18,534.1** | **(77.1)** | **(174.2)** | **(314.5)** | **(454.1)** | **(594.0)** | **$ 14,534.4** | **$ 15,342.4** | **$ 16,271.0** | **$ 17,148.5** | **$ 17,940.2** |
| Allowed Return: | | | | | | | | | | | | | | | |
| Third-Party long-term debt | 4.04% | 4.04% | 4.04% | 4.04% | 4.04% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 4.04% | 4.04% | 4.04% | 4.04% | 4.04% |
| Deemed long-term debt | 4.04% | 4.04% | 4.04% | 4.04% | 4.04% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 4.04% | 4.04% | 4.04% | 4.04% | 4.04% |
| Short-term debt | 1.56% | 1.56% | 1.56% | 1.56% | 1.56% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 1.56% | 1.56% | 1.56% | 1.56% | 1.56% |
| Common equity | 8.34% | 8.34% | 8.34% | 8.34% | 8.34% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 8.34% | 8.34% | 8.34% | 8.34% | 8.34% |
| Return on Capital: | | | | | | | | | | | | | | | |
| Third-Party long-term debt | $ - | $ - | $ - | $ - | $ - | - | - | - | - | - | $ - | $ - | $ - | $ - | $ - |
| Deemed long-term debt | $ 330.9 | $ 351.3 | $ 375.5 | $ 398.6 | $ 419.7 | $ (1.8) | $ (4.0) | $ (7.2) | $ (10.3) | $ (13.5) | $ 329.1 | $ 347.4 | $ 368.4 | $ 388.3 | $ 406.2 |
| Short-term debt | $ 9.1 | $ 9.7 | $ 10.3 | $ 11.0 | $ 11.6 | (0.0) | (0.1) | (0.2) | (0.3) | (0.4) | $ 9.1 | $ 9.6 | $ 10.1 | $ 10.7 | $ 11.2 |
| Total return on debt | **$ 340.0** | **$ 361.0** | **$ 385.9** | **$ 409.6** | **$ 431.2** | **$ (1.8)** | **$ (4.1)** | **$ (7.4)** | **$ (10.6)** | **$ (13.9)** | **$ 338.1** | **$ 356.9** | **$ 378.5** | **$ 398.9** | **$ 417.4** |
| | | | | | | | | | | | | | | | |
| Common equity | **$ 487.4** | **$ 517.6** | **$ 553.3** | **$ 587.2** | **$ 618.3** | **$ (2.6)** | **$ (5.8)** | **$ (10.5)** | **$ (15.2)** | **$ (19.8)** | **$ 484.9** | **$ 511.8** | **$ 542.8** | **$ 572.1** | **$ 598.5** |

**HYDRO ONE NETWORKS INC.**
**TRANSMISSION**
**Transmission Cost of Long-Term Debt Capital**
**Test Year (2023)**
**Year ending December 31**

| Line No. | Offering Date | Coupon Rate | Maturity Date | Principal Amount Offered ($Millions) | Premium Discount and Expenses ($Millions) | Net Capital Employed: Total Amount ($Millions) | Net Capital Employed: Per $100 Principal Amount (Dollars) | Effective Cost Rate | Total Amount Outstanding: 1/1/2022 at 12/31/22 ($Millions) | Total Amount Outstanding: 1/1/2023 at 12/31/23 ($Millions) | 1/1/2023 Avg. Monthly Averages ($Millions) | Carrying Cost ($Millions) | Projected Average Embedded Cost Rates |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 3-Jun-00 | 7.350% | 3-Jun-30 | 278.4 | 4.5 | 273.9 | 98.4 | 7.49% | 278.4 | 278.4 | 278.4 | 20.8 | |
| 2 | 22-Jun-01 | 6.930% | 1-Jun-32 | 109.3 | 1.3 | 107.9 | 98.8 | 7.03% | 109.3 | 109.3 | 109.3 | 7.7 | |
| 3 | 17-Sep-02 | 6.930% | 1-Jun-32 | 58.0 | (2.1) | 60.1 | 103.6 | 6.65% | 58.0 | 58.0 | 58.0 | 3.9 | |
| 4 | 31-Jan-03 | 6.350% | 31-Jan-34 | 126.0 | 1.0 | 125.0 | 99.2 | 6.41% | 126.0 | 126.0 | 126.0 | 8.1 | |
| 5 | 22-Apr-03 | 6.590% | 22-Apr-43 | 145.0 | 1.1 | 143.9 | 99.3 | 6.64% | 145.0 | 145.0 | 145.0 | 9.6 | |
| 6 | 25-Jun-04 | 6.350% | 31-Jan-34 | 72.0 | (0.2) | 72.2 | 100.2 | 6.33% | 72.0 | 72.0 | 72.0 | 4.6 | |
| 7 | 20-Aug-04 | 6.590% | 22-Apr-43 | 39.0 | (3.1) | 42.1 | 107.9 | 6.06% | 39.0 | 39.0 | 39.0 | 2.4 | |
| 8 | 24-Aug-04 | 6.350% | 31-Jan-34 | 39.0 | (1.4) | 40.4 | 103.5 | 6.09% | 39.0 | 39.0 | 39.0 | 2.4 | |
| 9 | 19-May-05 | 5.360% | 20-May-36 | 228.9 | 8.7 | 220.2 | 96.2 | 5.62% | 228.9 | 228.9 | 228.9 | 12.9 | |
| 10 | 24-Apr-06 | 5.360% | 20-May-36 | 187.5 | 2.5 | 185.0 | 98.7 | 5.45% | 187.5 | 187.5 | 187.5 | 10.2 | |
| 11 | 19-Oct-06 | 5.000% | 19-Oct-46 | 30.0 | 0.2 | 29.8 | 99.3 | 5.04% | 30.0 | 30.0 | 30.0 | 1.5 | |
| 12 | 13-Mar-07 | 4.890% | 13-Mar-37 | 240.0 | 1.3 | 238.7 | 99.4 | 4.93% | 240.0 | 240.0 | 240.0 | 11.8 | |
| 13 | 3-Mar-09 | 6.030% | 3-Mar-39 | 195.0 | 1.2 | 193.8 | 99.4 | 6.07% | 195.0 | 195.0 | 195.0 | 11.8 | |
| 14 | 16-Jul-09 | 5.490% | 16-Jul-40 | 210.0 | 1.4 | 208.6 | 99.4 | 5.53% | 210.0 | 210.0 | 210.0 | 11.6 | |
| 15 | 15-Mar-10 | 5.490% | 24-Jul-40 | 120.0 | (0.7) | 120.7 | 100.6 | 5.45% | 120.0 | 120.0 | 120.0 | 6.5 | |
| 16 | 15-Mar-10 | 4.400% | 4-Jun-20 | 180.0 | 0.8 | 179.2 | 99.5 | 4.46% | 0.0 | 0.0 | - | 0.0 | |
| 17 | 13-Sep-10 | 5.000% | 19-Oct-46 | 150.0 | (0.4) | 150.4 | 100.2 | 4.98% | 150.0 | 150.0 | 150.0 | 7.5 | |
| 18 | 26-Sep-11 | 4.390% | 26-Sep-41 | 205.0 | 1.3 | 203.7 | 99.3 | 4.43% | 205.0 | 205.0 | 205.0 | 9.1 | |
| 19 | 22-Dec-11 | 4.000% | 22-Dec-51 | 70.0 | 0.4 | 69.6 | 99.5 | 4.03% | 70.0 | 70.0 | 70.0 | 2.8 | |
| 20 | 13-Jan-12 | 3.200% | 13-Jan-22 | 154.0 | 0.8 | 153.2 | 99.5 | 3.26% | 0.0 | 0.0 | - | 0.0 | |
| 21 | 22-May-12 | 3.200% | 13-Jan-22 | 165.0 | (1.6) | 166.6 | 101.0 | 3.08% | 0.0 | 0.0 | - | 0.0 | |
| 22 | 22-May-12 | 4.000% | 22-Dec-51 | 68.8 | 0.3 | 68.4 | 99.5 | 4.02% | 68.8 | 68.8 | 68.8 | 2.8 | |
| 23 | 31-Jul-12 | 3.790% | 31-Jul-62 | 52.5 | 0.3 | 52.2 | 99.5 | 3.81% | 52.5 | 52.5 | 52.5 | 2.0 | |
| 24 | 16-Aug-12 | 3.790% | 31-Jul-62 | 141.0 | 1.1 | 139.9 | 99.2 | 3.83% | 141.0 | 141.0 | 141.0 | 5.4 | |
| 25 | 9-Oct-13 | 4.590% | 9-Oct-43 | 239.3 | 1.4 | 237.9 | 99.4 | 4.63% | 239.3 | 239.3 | 239.3 | 11.1 | |
| 26 | 29-Jan-14 | 4.310% | 29-Jan-64 | 30.0 | 0.2 | 29.8 | 99.4 | 4.34% | 30.0 | 30.0 | 30.0 | 1.3 | |
| 27 | 3-Jun-14 | 4.190% | 3-Jun-44 | 198.0 | 1.2 | 196.8 | 99.4 | 4.23% | 198.0 | 198.0 | 198.0 | 8.4 | |
| 28 | 24-Feb-16 | 3.910% | 24-Feb-46 | 175.0 | 1.1 | 173.9 | 99.4 | 3.95% | 175.0 | 175.0 | 175.0 | 6.9 | |
| 29 | 24-Feb-16 | 2.770% | 24-Feb-26 | 245.0 | 1.1 | 243.9 | 99.6 | 2.82% | 245.0 | 245.0 | 245.0 | 6.9 | |
| 30 | 24-Feb-16 | 1.840% | 24-Feb-21 | 250.0 | 0.9 | 249.1 | 99.6 | 1.92% | 0.0 | 0.0 | - | 0.0 | |
| 31 | 18-Nov-16 | 3.720% | 18-Nov-47 | 270.0 | 1.4 | 268.7 | 99.5 | 3.75% | 270.0 | 270.0 | 270.0 | 10.1 | |
| 32 | 26-Jun-18 | 3.630% | 25-Jun-49 | 468.0 | 2.4 | 465.6 | 99.5 | 3.66% | 468.0 | 468.0 | 468.0 | 17.1 | |
| 33 | 26-Jun-18 | 2.970% | 26-Jun-25 | 218.4 | 0.9 | 217.5 | 99.6 | 3.03% | 218.4 | 218.4 | 218.4 | 6.6 | |
| 34 | 5-Apr-19 | 3.640% | 5-Apr-49 | 147.5 | 0.8 | 146.7 | 99.4 | 3.67% | 147.5 | 147.5 | 147.5 | 5.4 | |
| 35 | 5-Apr-19 | 3.020% | 5-Apr-29 | 324.5 | 1.4 | 323.1 | 99.6 | 3.07% | 324.5 | 324.5 | 324.5 | 10.0 | |
| 36 | 5-Apr-19 | 2.540% | 5-Apr-24 | 413.0 | 1.6 | 411.4 | 99.6 | 2.62% | 413.0 | 413.0 | 413.0 | 10.8 | |
| 37 | 28-Feb-20 | 2.710% | 28-Feb-50 | 147.9 | 0.9 | 147.0 | 99.4 | 2.74% | 147.9 | 147.9 | 147.9 | 4.0 | |
| 38 | 28-Feb-20 | 2.160% | 28-Feb-30 | 197.2 | 0.8 | 196.4 | 99.6 | 2.21% | 197.2 | 197.2 | 197.2 | 4.4 | |
| 39 | 28-Feb-20 | 1.760% | 28-Feb-25 | 197.2 | 0.7 | 196.5 | 99.6 | 1.84% | 197.2 | 197.2 | 197.2 | 3.6 | |
| 40 | 9-Oct-20 | 2.710% | 28-Feb-50 | 124.0 | 0.4 | 123.6 | 99.7 | 2.73% | 124.0 | 124.0 | 124.0 | 3.4 | |
| 41 | 9-Oct-20 | 1.690% | 16-Jan-31 | 248.0 | 1.2 | 246.8 | 99.5 | 1.74% | 248.0 | 248.0 | 248.0 | 4.3 | |
| 42 | 9-Oct-20 | 0.710% | 16-Jan-23 | 124.0 | 0.9 | 123.1 | 99.3 | 1.04% | 124.0 | 0.0 | 9.5 | 0.1 | |
| 43 | 15-Mar-21 | 2.860% | 15-Mar-51 | 128.3 | 0.6 | 127.7 | 99.5 | 2.88% | 128.3 | 128.3 | 128.3 | 3.7 | |
| 44 | 15-Jun-21 | 1.859% | 15-Jun-31 | 128.3 | 0.6 | 127.7 | 99.5 | 1.91% | 128.3 | 128.3 | 128.3 | 2.5 | |
| 45 | 15-Sep-21 | 1.327% | 15-Sep-26 | 128.3 | 0.6 | 127.7 | 99.5 | 1.43% | 128.3 | 128.3 | 128.3 | 1.8 | |
| 46 | 15-Mar-22 | 3.610% | 15-Mar-52 | 239.6 | 1.2 | 238.4 | 99.5 | 3.64% | 239.6 | 239.6 | 239.6 | 8.7 | |
| 47 | 15-Jun-22 | 2.609% | 15-Jun-32 | 239.6 | 1.2 | 238.4 | 99.5 | 2.67% | 239.6 | 239.6 | 239.6 | 6.4 | |
| 48 | 15-Sep-22 | 2.077% | 15-Sep-27 | 239.6 | 1.2 | 238.4 | 99.5 | 2.18% | 239.6 | 239.6 | 239.6 | 5.2 | |
| 49 | 15-Mar-23 | 4.010% | 15-Mar-53 | 218.1 | 1.1 | 217.0 | 99.5 | 4.04% | 0.0 | 218.1 | 167.8 | 6.8 | |
| 50 | 15-Jun-23 | 3.009% | 15-Jun-33 | 218.1 | 1.1 | 217.0 | 99.5 | 3.07% | 0.0 | 218.1 | 117.4 | 3.6 | |
| 51 | 15-Sep-23 | 2.477% | 15-Sep-28 | 218.1 | 1.1 | 217.0 | 99.5 | 2.58% | 0.0 | 218.1 | 67.1 | 1.7 | |
| 52 | | **Subtotal** | | | | | | | 7,635.9 | 8,166.2 | 7,873.7 | 310.2 | |
| 53 | | Treasury OM&A costs | | | | | | | | | | 2.1 | |
| 54 | | Other financing-related fees | | | | | | | | | | 5.8 | |
| 55 | | **Total** | | | | | | | 7,635.9 | 8,166.2 | 7,873.7 | 318.2 | 4.04% |

**Hydro One Networks Inc.**
**Implementation of Decision in EB-2021-0110**

**Transmission Regulatory Taxes**

| ($ millions) | Supporting Reference | Hydro One Proposed | | | | | OEB Decision Impact | | | | | OEB Approved | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | 2023 | 2024 | 2025 | 2026 | 2027 | 2023 | 2024 | 2025 | 2026 | 2027 | 2023 | 2024 | 2025 | 2026 | 2027 |
| Regulatory Taxes | *See supporting details below* | 39.8 | 70.0 | 59.1 | 80.9 | 81.7 | 4.0 | 4.3 | 6.5 | 3.5 | 4.5 | 43.8 | 74.2 | 65.6 | 84.4 | 86.3 |

***Income Tax Supporting Details***

| | | | HOP 2023 | HOP 2024 | HOP 2025 | HOP 2026 | HOP 2027 | Impact 2023 | Impact 2024 | Impact 2025 | Impact 2026 | Impact 2027 | Approved 2023 | Approved 2024 | Approved 2025 | Approved 2026 | Approved 2027 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Rate Base | Exhibit 1.2 | (a) | $ 14,612 | $ 15,517 | $ 16,585 | $ 17,603 | $ 18,534 | $ (77) | $ (174) | $ (314) | $ (454) | $ (594) | $ 14,534 | $ 15,342 | $ 16,271 | $ 17,148 | $ 17,940 |
| Common Equity Capital Structure | | (b) | 40.0% | 40.0% | 40.0% | 40.0% | 40.0% | | | | | | 40.0% | 40.0% | 40.0% | 40.0% | 40.0% |
| Return on Equity | Exhibit 1.4 | (c) | 8.34% | 8.34% | 8.34% | 8.34% | 8.34% | | | | | | 8.34% | 8.34% | 8.34% | 8.34% | 8.34% |
| Return on Equity | | (d) = a x b x c | 487.4 | 517.6 | 553.3 | 587.2 | 618.3 | (2.6) | (5.8) | (10.5) | (15.2) | (19.8) | 484.9 | 511.8 | 542.8 | 572.1 | 598.5 |
| Regulatory Income Tax | | (e) = l | 39.8 | 70.0 | 59.1 | 80.9 | 81.7 | 4.0 | 4.3 | 6.5 | 3.5 | 4.5 | 43.8 | 74.2 | 65.6 | 84.4 | 86.3 |
| Regulatory Net Income (before tax) | | (f) = d + e | 527.2 | 587.6 | 612.4 | 668.2 | 700.0 | 1.5 | (1.5) | (4.0) | (11.6) | (15.3) | 528.7 | 586.1 | 608.4 | 656.5 | 684.7 |
| Timing Differences *(Note 1)* | | (g) | (375.9) | (322.3) | (388.2) | (361.5) | (390.3) | 13.8 | 17.7 | 28.5 | 24.9 | 32.4 | (362.2) | (304.7) | (359.6) | (336.6) | (358.0) |
| Taxable Income | | (h) = f + g | 151.3 | 265.3 | 224.2 | 306.6 | 309.7 | 15.2 | 16.1 | 24.5 | 13.2 | 17.1 | 166.5 | 281.4 | 248.8 | 319.9 | 326.8 |
| Tax Rate | | (i) | 26.5% | 26.5% | 26.5% | 26.5% | 26.5% | | | | | | 26.5% | 26.5% | 26.5% | 26.5% | 26.5% |
| Income Tax | | (j) = h x i | 40.1 | 70.3 | 59.4 | 81.3 | 82.1 | | | | | | 44.1 | 74.6 | 65.9 | 84.8 | 86.6 |
| less: Income Tax Credits | | (k) | (0.3) | (0.3) | (0.3) | (0.3) | (0.3) | | | | | | (0.3) | (0.3) | (0.3) | (0.3) | (0.3) |
| Regulatory Income Tax | | (l) = j + k | 39.8 | 70.0 | 59.1 | 80.9 | 81.7 | 4.0 | 4.3 | 6.5 | 3.5 | 4.5 | 43.8 | 74.2 | 65.6 | 84.4 | 86.3 |
| Income Taxes | | | 39.8 | 70.0 | 59.1 | 80.9 | 81.7 | 4.0 | 4.3 | 6.5 | 3.5 | 4.5 | 43.8 | 74.2 | 65.6 | 84.4 | 86.3 |
| Note 1. Book to Tax Timing Differences | | | | | | | | | | | | | | | | | |
| Depreciation | | | 531.9 | 562.7 | 601.0 | 634.3 | 658.0 | (8.2) | (11.5) | (16.1) | (20.1) | (23.2) | 523.7 | 551.2 | 584.9 | 614.1 | 634.8 |
| CCA | Exhibit O-1-2, Attachment 9 | | (794.4) | (769.1) | (874.0) | (885.9) | (936.4) | 14.3 | 21.6 | 37.9 | 44.8 | 55.0 | (780.0) | (747.6) | (836.1) | (841.1) | (881.4) |
| Other Timing Differences | | | (113.5) | (115.9) | (115.2) | (109.8) | (111.9) | 7.7 | 7.6 | 6.8 | 0.2 | 0.5 | (105.8) | (108.3) | (108.5) | (109.7) | (111.4) |
| Total Timing Differences | | | (375.9) | (322.3) | (388.2) | (361.5) | (390.3) | 13.8 | 17.7 | 28.5 | 24.9 | 32.4 | (362.2) | (304.7) | (359.6) | (336.6) | (358.0) |

**HYDRO ONE NETWORKS INC.**
**TRANSMISSION**
**Calculation of Utility Income Taxes**
**Test Years (2023 to 2027)**
**Year Ending December 31**
($ Millions)

| Line No. | Particulars | | **2023** | **2024** | **2025** | **2026** | **2027** |
|---|---|---|---|---|---|---|---|
| | Determination of Taxable Income | | | | | | |
| 1 | Regulatory Net Income (before tax) | $ | 528.7 | 586.1 | 608.4 | 656.5 | 684.7 |
| 2 | Book to Tax Adjustments: | | - | - | - | - | - |
| 3 | Other Post Employment Benefits expense | | 31.2 | 32.1 | 33.1 | 34.0 | 35.6 |
| 4 | Other Post Employment Benefits payments | | (29.1) | (29.9) | (30.9) | (31.8) | (32.6) |
| 5 | Depreciation and amortization | | 531.3 | 558.7 | 591.5 | 614.1 | 634.8 |
| 7 | Capital Cost Allowance | | (780.0) | (747.6) | (836.1) | (841.1) | (881.4) |
| 8 | Removal costs | | (3.7) | (3.7) | (3.7) | (3.7) | (3.7) |
| 9 | Environmental costs | | (7.6) | (7.5) | (6.6) | - | - |
| 10 | Hedge loss - amortization | | - | - | - | - | - |
| 11 | Non-deductible meals & entertainment | | 3.0 | 3.0 | 3.0 | 3.0 | 3.0 |
| 12 | Capital amounts expensed under $2K | | - | - | - | - | - |
| 13 | Research & Development ITC | | - | - | - | - | - |
| 14 | Ontario education credits | | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 |
| 15 | Capitalized overhead costs | | (72.6) | (73.6) | (74.4) | (74.7) | (75.3) |
| 16 | Capitalized pension costs | | (34.5) | (36.2) | (35.9) | (36.6) | (39.1) |
| 17 | Debt Issuance costs - amortization | | 2.7 | 2.8 | 3.0 | 3.3 | 3.6 |
| 18 | Debt Issuance costs - 21e deduction | | (3.9) | (3.8) | (3.6) | (4.1) | (3.8) |
| 19 | Premium/Discount - amortization | | (0.2) | (0.2) | (0.2) | (0.2) | (0.3) |
| 20 | Bond discount deduction | | - | - | - | - | - |
| 21 | Non-deductible LTIP | | - | - | - | - | - |
| 22 | Capital Contribution True-Up Adjustment | | - | - | - | - | - |
| 23 | Other | | 0.9 | 0.9 | 0.9 | 0.8 | 0.8 |
| | | $ | (362.2) | (304.7) | (359.6) | (336.6) | (358.0) |
| 23 | Regulatory Taxable Income | $ | 166.5 | 281.4 | 248.8 | 319.9 | 326.8 |
| 24 | Corporate Income Tax Rate | % | 26.5 | 26.5 | 26.5 | 26.5 | 26.5 |
| 25 | Subtotal | $ | 44.1 | 74.6 | 65.9 | 84.8 | 86.6 |
| 26 | Less: R&D ITC / Ontario education credits | | (0.3) | (0.3) | (0.3) | (0.3) | (0.3) |
| 27 | Regulatory Income Tax | $ | 43.8 | 74.2 | 65.6 | 84.4 | 86.3 |

**HYDRO ONE NETWORKS INC.**
**TRANSMISSION**
**Calculation of Utility Income Taxes**
**Test Years (2023 to 2027)**
**Year Ending December 31**
($ Millions)

| 2023 CCA Calculation | CCA Class | Opening UCC | Net Additions | UCC pre-1/2 yr | 50% Net Additions | Bonus Depreciation | UCC for CCA | CCA Rate | CCA | Closing UCC |
|---|---|---|---|---|---|---|---|---|---|---|
| | 1 | 1,754.5 | 22.8 | 1,777.3 | 11.4 | 22.8 | 1,788.7 | 4% | 71.5 | 1,705.8 |
| | 2 | 347.4 | - | 347.4 | - | - | 347.4 | 6% | 20.8 | 326.5 |
| | 3 | 176.8 | - | 176.8 | - | - | 176.8 | 5% | 8.8 | 167.9 |
| | 6 | 43.0 | - | 43.0 | - | - | 43.0 | 10% | 4.3 | 38.7 |
| | 7 | 1.2 | - | 1.2 | - | - | 1.2 | 15% | 0.2 | 1.0 |
| | 8 | 183.6 | 107.6 | 291.3 | 53.8 | 107.6 | 345.1 | 20% | 69.0 | 222.3 |
| | 9 | 0.9 | - | 0.9 | - | - | 0.9 | 25% | 0.2 | 0.7 |
| | 10 | 20.6 | 15.6 | 36.2 | 7.8 | 15.6 | 44.0 | 30% | 13.2 | 23.0 |
| | 12 | - | 21.9 | 21.9 | 11.0 | 11.0 | 21.9 | 100% | 21.9 | - |
| | 13 | 4.1 | - | 4.1 | - | - | 4.1 | N/A | 1.3 | 2.8 |
| | 14.1 | 34.3 | 6.1 | 40.4 | 3.1 | 6.1 | 43.5 | 5% | 2.2 | 38.3 |
| | 17 | 97.2 | 2.7 | 99.9 | 1.4 | 2.7 | 101.3 | 8% | 8.1 | 91.8 |
| | 35 | 0.1 | - | 0.1 | - | - | 0.1 | 7% | 0.0 | 0.1 |
| | 42 | 39.0 | - | 39.0 | - | - | 39.0 | 12% | 4.7 | 34.3 |
| | 45 | 0.0 | - | 0.0 | - | - | 0.0 | 45% | 0.0 | 0.0 |
| | 46 | 3.9 | - | 3.9 | - | - | 3.9 | 30% | 1.2 | 2.8 |
| | 47 | 5,344.7 | 1,017.6 | 6,362.3 | 508.8 | 1,017.6 | 6,871.1 | 8% | 549.7 | 5,812.6 |
| | 50 | 7.0 | 5.7 | 12.7 | 2.9 | 5.7 | 15.6 | 55% | 8.6 | 4.1 |
| | 52 | - | - | - | - | - | - | 100% | - | - |
| | ECE | 23.9 | - | 23.9 | - | - | 23.9 | 7% | 1.7 | 22.3 |
| | | 8,082.1 | 1,200.2 | 9,282.4 | 600.1 | 1,189.3 | 9,871.5 | | 787.5 | 8,494.9 |
| | | | | | | | | | (7.4) | Non-Regulatory |
| | | | | | | | | | 780.0 | Total CCA for RR |

**HYDRO ONE NETWORKS INC.**
**TRANSMISSION**
**Calculation of Utility Income Taxes**
**Test Years (2023 to 2027)**
**Year Ending December 31**
($ Millions)

| **2024 CCA Calculation** | CCA Class | Opening UCC | Net Additions | UCC pre-1/2 yr | 50% Net Additions | Bonus Depreciation | UCC for CCA | CCA Rate | CCA | Closing UCC |
|---|---|---|---|---|---|---|---|---|---|---|
| | 1 | 1,705.8 | 46.0 | 1,751.7 | 23.0 | 23.0 | 1,751.7 | 4% | 70.1 | 1,681.7 |
| | 2 | 326.5 | - | 326.5 | - | - | 326.5 | 6% | 19.6 | 306.9 |
| | 3 | 167.9 | - | 167.9 | - | - | 167.9 | 5% | 8.4 | 159.5 |
| | 6 | 38.7 | - | 38.7 | - | - | 38.7 | 10% | 3.9 | 34.9 |
| | 7 | 1.0 | - | 1.0 | - | - | 1.0 | 15% | 0.1 | 0.8 |
| | 8 | 222.3 | 85.0 | 307.3 | 42.5 | 42.5 | 307.3 | 20% | 61.5 | 245.8 |
| | 9 | 0.7 | - | 0.7 | - | - | 0.7 | 25% | 0.2 | 0.5 |
| | 10 | 23.0 | 15.6 | 38.6 | 7.8 | 7.8 | 38.6 | 30% | 11.6 | 27.0 |
| | 12 | - | 16.6 | 16.6 | 8.3 | 8.3 | 16.6 | 100% | 16.6 | - |
| | 13 | 2.8 | - | 2.8 | - | - | 2.8 | N/A | 1.3 | 1.5 |
| | 14.1 | 38.3 | 7.4 | 45.6 | 3.7 | 3.7 | 45.6 | 5% | 2.3 | 43.4 |
| | 17 | 91.8 | 0.9 | 92.7 | 0.5 | 0.5 | 92.7 | 8% | 7.4 | 85.3 |
| | 35 | 0.1 | - | 0.1 | - | - | 0.1 | 7% | 0.0 | 0.1 |
| | 42 | 34.3 | - | 34.3 | - | - | 34.3 | 12% | 4.1 | 30.2 |
| | 45 | 0.0 | - | 0.0 | - | - | 0.0 | 45% | 0.0 | 0.0 |
| | 46 | 2.8 | - | 2.8 | - | - | 2.8 | 30% | 0.8 | 1.9 |
| | 47 | 5,812.6 | 949.3 | 6,761.9 | 474.6 | 474.6 | 6,761.9 | 8% | 541.0 | 6,220.9 |
| | 50 | 4.1 | 3.2 | 7.3 | 1.6 | 1.6 | 7.3 | 55% | 4.0 | 3.3 |
| | 52 | - | - | - | - | - | - | 100% | - | - |
| | ECE | 22.3 | - | 22.3 | - | - | 22.3 | 7% | 1.6 | 20.7 |
| | | 8,494.9 | 1,124.0 | 9,618.9 | 562.0 | 562.0 | 9,618.9 | | 754.4 | 8,864.5 |
| | | | | | | | | | (6.8) | Non-Regulatory |
| | | | | | | | | | 747.6 | Total CCA for RR |

**HYDRO ONE NETWORKS INC.**
**TRANSMISSION**
**Calculation of Utility Income Taxes**
**Test Years (2023 to 2027)**
**Year Ending December 31**
($ Millions)

| **2025 CCA Calculation** | CCA Class | Opening UCC | Net Additions | UCC pre-1/2 yr | 50% Net Additions | Bonus Depreciation | UCC for CCA | CCA Rate | CCA | Closing UCC |
|---|---|---|---|---|---|---|---|---|---|---|
| | 1 | 1,681.7 | 28.2 | 1,709.9 | 14.1 | 14.1 | 1,709.9 | 4% | 68.4 | 1,641.5 |
| | 2 | 306.9 | - | 306.9 | - | - | 306.9 | 6% | 18.4 | 288.5 |
| | 3 | 159.5 | - | 159.5 | - | - | 159.5 | 5% | 8.0 | 151.6 |
| | 6 | 34.9 | - | 34.9 | - | - | 34.9 | 10% | 3.5 | 31.4 |
| | 7 | 0.8 | - | 0.8 | - | - | 0.8 | 15% | 0.1 | 0.7 |
| | 8 | 245.8 | 91.9 | 337.7 | 45.9 | 45.9 | 337.7 | 20% | 67.5 | 270.2 |
| | 9 | 0.5 | - | 0.5 | - | - | 0.5 | 25% | 0.1 | 0.4 |
| | 10 | 27.0 | 16.5 | 43.6 | 8.3 | 8.3 | 43.6 | 30% | 13.1 | 30.5 |
| | 12 | - | 40.8 | 40.8 | 20.4 | 20.4 | 40.8 | 100% | 40.8 | - |
| | 13 | 1.5 | - | 1.5 | - | - | 1.5 | N/A | 1.5 | (0.0) |
| | 14.1 | 43.4 | 9.7 | 53.1 | 4.9 | 4.9 | 53.1 | 5% | 2.7 | 50.4 |
| | 17 | 85.3 | 3.3 | 88.7 | 1.7 | 1.7 | 88.7 | 8% | 7.1 | 81.6 |
| | 35 | 0.1 | - | 0.1 | - | - | 0.1 | 7% | 0.0 | 0.0 |
| | 42 | 30.2 | - | 30.2 | - | - | 30.2 | 12% | 3.6 | 26.6 |
| | 45 | 0.0 | - | 0.0 | - | - | 0.0 | 45% | 0.0 | 0.0 |
| | 46 | 1.9 | - | 1.9 | - | - | 1.9 | 30% | 0.6 | 1.3 |
| | 47 | 6,220.9 | 1,301.6 | 7,522.6 | 650.8 | 650.8 | 7,522.6 | 8% | 601.8 | 6,920.7 |
| | 50 | 3.3 | 3.4 | 6.7 | 1.7 | 1.7 | 6.7 | 55% | 3.7 | 3.0 |
| | 52 | - | - | - | - | - | - | 100% | - | - |
| | ECE | 20.7 | - | 20.7 | - | - | 20.7 | 7% | 1.4 | 19.2 |
| | | 8,864.5 | 1,495.4 | 10,360.0 | 747.7 | 747.7 | 10,360.0 | | 842.3 | 9,517.6 |
| | | | | | | | | | (6.2) | Non-Regulatory |
| | | | | | | | | | 836.1 | Total CCA for RR |

# HYDRO ONE NETWORKS INC.
## TRANSMISSION
## Calculation of Utility Income Taxes
## Test Years (2023 to 2027)
## Year Ending December 31
($ Millions)

| 2026 CCA Calculation | CCA Class | Opening UCC | Net Additions | UCC pre-1/2 yr | 50% Net Additions | Bonus Depreciation | UCC for CCA | CCA Rate | CCA | Closing UCC |
|---|---|---|---|---|---|---|---|---|---|---|
| | 1 | 1,641.5 | 28.9 | 1,670.3 | 14.4 | 14.4 | 1,670.3 | 4% | 66.8 | 1,603.5 |
| | 2 | 288.5 | - | 288.5 | - | - | 288.5 | 6% | 17.3 | 271.2 |
| | 3 | 151.6 | - | 151.6 | - | - | 151.6 | 5% | 7.6 | 144.0 |
| | 6 | 31.4 | - | 31.4 | - | - | 31.4 | 10% | 3.1 | 28.2 |
| | 7 | 0.7 | - | 0.7 | - | - | 0.7 | 15% | 0.1 | 0.6 |
| | 8 | 270.2 | 90.7 | 360.9 | 45.4 | 45.4 | 360.9 | 20% | 72.2 | 288.7 |
| | 9 | 0.4 | - | 0.4 | - | - | 0.4 | 25% | 0.1 | 0.3 |
| | 10 | 30.5 | 16.1 | 46.6 | 8.1 | 8.1 | 46.6 | 30% | 14.0 | 32.6 |
| | 12 | - | 20.5 | 20.5 | 10.3 | 10.3 | 20.5 | 100% | 20.5 | - |
| | 13 | (0.0) | - | (0.0) | - | - | (0.0) | N/A | 0.1 | (0.1) |
| | 14.1 | 50.4 | 8.9 | 59.3 | 4.4 | 4.4 | 59.3 | 5% | 3.0 | 56.3 |
| | 17 | 81.6 | 1.9 | 83.5 | 0.9 | 0.9 | 83.5 | 8% | 6.7 | 76.8 |
| | 35 | 0.0 | - | 0.0 | - | - | 0.0 | 7% | 0.0 | 0.0 |
| | 42 | 26.6 | - | 26.6 | - | - | 26.6 | 12% | 3.2 | 23.4 |
| | 45 | 0.0 | - | 0.0 | - | - | 0.0 | 45% | 0.0 | 0.0 |
| | 46 | 1.3 | - | 1.3 | - | - | 1.3 | 30% | 0.4 | 0.9 |
| | 47 | 6,920.7 | 910.8 | 7,831.5 | 455.4 | 455.4 | 7,831.5 | 8% | 626.5 | 7,205.0 |
| | 50 | 3.0 | 4.0 | 7.0 | 2.0 | 2.0 | 7.0 | 55% | 3.8 | 3.1 |
| | 52 | - | - | - | - | - | - | 100% | - | - |
| | ECE | 19.2 | - | 19.2 | - | - | 19.2 | 7% | 1.3 | 17.9 |
| | | 9,517.6 | 1,081.8 | 10,599.4 | 540.9 | 540.9 | 10,599.4 | | 846.8 | 9,752.6 |
| | | | | | | | | | (5.7) | Non-Regulatory |
| | | | | | | | | | 841.1 | Total CCA for RR |

**HYDRO ONE NETWORKS INC.**
**TRANSMISSION**
**Calculation of Utility Income Taxes**
**Test Years (2023 to 2027)**
**Year Ending December 31**
($ Millions)

| **2027 CCA Calculation** | CCA Class | Opening UCC | Net Additions | UCC pre-1/2 yr | 50% Net Additions | Bonus Depreciation | UCC for CCA | CCA Rate | CCA | Closing UCC |
|---|---|---|---|---|---|---|---|---|---|---|
| | 1 | 1,603.5 | 24.3 | 1,627.8 | 12.2 | 12.2 | 1,627.8 | 4% | 65.1 | 1,562.7 |
| | 2 | 271.2 | - | 271.2 | - | - | 271.2 | 6% | 16.3 | 254.9 |
| | 3 | 144.0 | - | 144.0 | - | - | 144.0 | 5% | 7.2 | 136.8 |
| | 6 | 28.2 | - | 28.2 | - | - | 28.2 | 10% | 2.8 | 25.4 |
| | 7 | 0.6 | - | 0.6 | - | - | 0.6 | 15% | 0.1 | 0.5 |
| | 8 | 288.7 | 51.1 | 339.9 | 25.6 | 25.6 | 339.9 | 20% | 68.0 | 271.9 |
| | 9 | 0.3 | - | 0.3 | - | - | 0.3 | 25% | 0.1 | 0.2 |
| | 10 | 32.6 | 17.1 | 49.7 | 8.5 | 8.5 | 49.7 | 30% | 14.9 | 34.8 |
| | 12 | - | 17.5 | 17.5 | 8.7 | 8.7 | 17.5 | 100% | 17.5 | - |
| | 13 | (0.1) | - | (0.1) | - | - | (0.1) | N/A | 1.0 | (1.1) |
| | 14.1 | 56.3 | 11.2 | 67.6 | 5.6 | 5.6 | 67.6 | 5% | 3.4 | 64.2 |
| | 17 | 76.8 | 1.5 | 78.3 | 0.8 | 0.8 | 78.3 | 8% | 6.3 | 72.0 |
| | 35 | 0.0 | - | 0.0 | - | - | 0.0 | 7% | 0.0 | 0.0 |
| | 42 | 23.4 | - | 23.4 | - | - | 23.4 | 12% | 2.8 | 20.6 |
| | 45 | 0.0 | - | 0.0 | - | - | 0.0 | 45% | 0.0 | 0.0 |
| | 46 | 0.9 | - | 0.9 | - | - | 0.9 | 30% | 0.3 | 0.7 |
| | 47 | 7,205.0 | 1,241.2 | 8,446.2 | 620.6 | 620.6 | 8,446.2 | 8% | 675.7 | 7,770.5 |
| | 50 | 3.1 | 4.8 | 8.0 | 2.4 | 2.4 | 8.0 | 55% | 4.4 | 3.6 |
| | 52 | - | - | - | - | - | - | 100% | - | - |
| | ECE | 17.9 | - | 17.9 | - | - | 17.9 | 5% | 0.9 | 17.0 |
| | | 9,752.6 | 1,368.8 | 11,121.3 | 684.4 | 684.4 | 11,121.3 | | 886.6 | 10,234.7 |
| | | | | | | | | | (5.3) | Non-Regulatory |
| | | | | | | | | | 881.4 | Total CCA for RR |

**Hydro One Networks Inc.**
**Implementation of Decision in EB-2021-0110**

**Transmission External Revenue**

| *($ millions)* | **Supporting Reference** | **Hydro One Proposed** | | | | | **OEB Decision Impact** | | | | | **OEB Approved** | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | **2023** | **2024** | **2025** | **2026** | **2027** | **2023** | **2024** | **2025** | **2026** | **2027** | **2023** | **2024** | **2025** | **2026** | **2027** |
| External Revenue | Exhibit D-02-01 | (40.1) | (36.2) | (36.5) | (36.2) | (37.3) | (0.7) | (0.7) | (0.6) | (0.7) | (0.7) | (40.8) | (36.9) | (37.1) | (36.9) | (37.9) |

OEB Decision Impact Supporting Details

| **Adjustments** | **Reference** | 2023 | 2024 | 2025 | 2026 | 2027 |
|---|---|---|---|---|---|---|
| External revenue update | Part C, Issue 39 | (0.7) | (0.7) | (0.6) | (0.7) | (0.7) |

**Hydro One Networks Inc.**
**Implementation of Decision in EB-2021-0110**

**Export Transmission Service Revenue**

| | | Hydro One Proposed | | | | | OEB Decision Impact | | | | | OEB Approved | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| *($ millions)* | Supporting Reference | 2023 | 2024 | 2025 | 2026 | 2027 | 2023 | 2024 | 2025 | 2026 | 2027 | 2023 | 2024 | 2025 | 2026 | 2027 |
| Export Transmission Service Revenue | | 37.4 | 37.1 | 37.3 | 37.2 | 37.2 | - | - | - | - | - | 37.4 | 37.1 | 37.3 | 37.2 | 37.2 |

**Hydro One Networks Inc.**
**Implementation of Decision in EB-2021-0110**

**Deferral and Variance Accounts - Transmission**

| ($ millions) | Supporting Reference | Hydro One Proposed | | | | | | OEB Decision Impact | | | | | OEB Approved | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Total | 2023 | 2024 | 2025 | 2026 | 2027 | 2023 | 2024 | 2025 | 2026 | 2027 | Total | 2023 | 2024 | 2025 | 2026 | 2027 |
| Deferral and Variance Accounts Disposition | *Exhibit O-1-5, Attachment 1* | (21.9) | (26.4) | 1.1 | 1.1 | 1.1 | 1.1 | 3.9 | (1.1) | (1.1) | (1.1) | (1.1) | (22.5) | (22.5) | - | - | - | - |
| | | | | | | | | | | | | | | | | | | |
| **Deferral and Variance Accounts Details** | | | | | | | | | | | | | | | | | | |
| Long-Term Transmission Future Corridor Acquisition and Development | | (0.0) | (0.0) | (0.0) | (0.0) | (0.0) | (0.0) | | | | | | (0.0) | (0.0) | | | | |
| LDC CDM and Demand Response Variance Account | | 26.8 | 5.4 | 5.4 | 5.4 | 5.4 | 5.4 | | | | | | 26.8 | 26.8 | | | | |
| Waasigan Transmission Deferral Account OMA | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | | | | | | 0.0 | 0.0 | | | | |
| OPEB Cost Deferral | | 29.5 | 5.9 | 5.9 | 5.9 | 5.9 | 5.9 | | | | | | 29.5 | 29.5 | | | | |
| Customer Connection and Cost Recovery Agreements (CCRA) True-Up Variance Account | | 0.6 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | | | | | | 0.6 | 0.6 | | | | |
| OPEB Asymmetrical Carrying Charge Account | | (1.0) | (0.2) | (0.2) | (0.2) | (0.2) | (0.2) | | | | | | (1.0) | (1.0) | | | | |
| Tax Rate Changes | | (21.0) | (4.2) | (4.2) | (4.2) | (4.2) | (4.2) | | | | | | (21.6) | (21.6) | | | | |
| Excess Export Service Revenue | | 1.1 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | | | | | | 1.1 | 1.1 | | | | |
| External Secondary Land Use Revenue | | (16.6) | (3.3) | (3.3) | (3.3) | (3.3) | (3.3) | | | | | | (16.6) | (16.6) | | | | |
| External Station Maintenance, E&CS and Other External Revenue | | 9.4 | 1.9 | 1.9 | 1.9 | 1.9 | 1.9 | | | | | | (18.1) | (18.1) | | | | |
| Rights Payments | | 0.9 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | | | | | | 0.9 | 0.9 | | | | |
| Pension Costs Differential | | (4.5) | (0.9) | (0.9) | (0.9) | (0.9) | (0.9) | | | | | | (4.5) | (4.5) | | | | |
| External Revenue – Partnership Transmission Projects Account | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | | | | | | 0.0 | 0.0 | | | | |
| Capital In-Service Variance Account | | (0.0) | (0.0) | (0.0) | (0.0) | (0.0) | (0.0) | | | | | | (0.0) | (0.0) | | | | |
| Depreciation Expense (Asset Removal Costs) Asymmetrical Cumulative Variance Account | | (19.6) | (3.9) | (3.9) | (3.9) | (3.9) | (3.9) | | | | | | (19.6) | (19.6) | | | | |
| 2013-2020 External Revenue Adjustment for Disposition | *O-01-05* | (27.5) | (27.5) | | | | | | | | | | | - | | | | |
| **Total Regulatory Accounts Seeking Disposition – Group 2** | | **(21.9)** | **(26.4)** | **1.1** | **1.1** | **1.1** | **1.1** | | | | | | **(22.5)** | **(22.5)** | **-** | **-** | **-** | **-** |

**Hydro One Networks Inc.**
**Implementation of Decision in EB-2021-0110**

**Transmission Working Capital Adjustment**

| | Hydro One Proposed | | | | | OEB Decision Impact | | | | | OEB Approved | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | **2023** | **2024** | **2025** | **2026** | **2027** | **2023** | **2024** | **2025** | **2026** | **2027** | **2023** | **2024** | **2025** | **2026** | **2027** |
| **Adjusted Working Capital in Rate Base** | **32.9** | **34.7** | **34.5** | **35.8** | **36.1** | **(1.6)** | **(1.5)** | **(1.4)** | **(1.4)** | **(1.3)** | **31.3** | **33.1** | **33.1** | **34.4** | **34.8** |
| Long-term debt | 4.04% | 4.04% | 4.04% | 4.04% | 4.04% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 4.04% | 4.04% | 4.04% | 4.04% | 4.04% |
| Short-term debt | 1.56% | 1.56% | 1.56% | 1.56% | 1.56% | | | | | | 1.56% | 1.56% | 1.56% | 1.56% | 1.56% |
| Common equity | 8.34% | 8.34% | 8.34% | 8.34% | 8.34% | | | | | | 8.34% | 8.34% | 8.34% | 8.34% | 8.34% |
| Return on Long-term debt | 0.7 | 0.8 | 0.8 | 0.8 | 0.8 | (0.0) | (0.0) | (0.0) | (0.0) | (0.0) | 0.7 | 0.8 | 0.7 | 0.8 | 0.8 |
| Return on Short-term debt | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | (0.0) | (0.0) | (0.0) | (0.0) | (0.0) | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Return on Common equity | 1.1 | 1.2 | 1.2 | 1.2 | 1.2 | (0.1) | (0.1) | (0.0) | (0.0) | (0.0) | 1.0 | 1.1 | 1.1 | 1.1 | 1.2 |
| **Total Return on Capital** | **1.9** | **2.0** | **2.0** | **2.0** | **2.0** | **(0.1)** | **(0.1)** | **(0.1)** | **(0.1)** | **(0.1)** | **1.8** | **1.9** | **1.9** | **1.9** | **2.0** |
| Income tax | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 | (0.0) | (0.0) | (0.0) | (0.0) | (0.0) | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 |
| **Total Revenue Requirement Associated with Working Capital in Rate Base** | **2.3** | **2.4** | **2.4** | **2.5** | **2.5** | **(0.1)** | **(0.1)** | **(0.1)** | **(0.1)** | **(0.1)** | **2.1** | **2.3** | **2.3** | **2.4** | **2.4** |
| Revenue Requirement Associated with Working Capital in rate base | 2.3 | 2.4 | 2.4 | 2.5 | 2.5 | (0.1) | (0.1) | (0.1) | (0.1) | (0.1) | 2.1 | 2.3 | 2.3 | 2.4 | 2.4 |
| Less Productivity Factor applied to Working Capital | - | (0.0) | (0.0) | (0.0) | (0.0) | | (0.0) | (0.0) | (0.0) | (0.0) | - | (0.0) | (0.0) | (0.0) | (0.0) |
| **Revenue Requirement calculation (prior methodology)** | **2.3** | **2.4** | **2.4** | **2.4** | **2.5** | **(0.1)** | **(0.1)** | **(0.1)** | **(0.1)** | **(0.1)** | **2.1** | **2.3** | **2.3** | **2.3** | **2.4** |
| Revenue Requirement calculation (OEB Decision) [1] | **2.3** | **2.3** | **2.3** | **2.4** | **2.4** | **(0.1)** | **(0.1)** | **(0.1)** | **(0.1)** | **(0.1)** | **2.1** | **2.2** | **2.2** | **2.3** | **2.3** |
| Difference between the two methodologies | - | (0.1) | (0.0) | (0.1) | (0.0) | | (0.0) | (0.0) | (0.0) | (0.0) | - | (0.1) | (0.0) | (0.1) | (0.0) |

Note [1]: The calculation for revenue requirement associated with working capital based on the OEB decision would exclude recovering incremental revenue associated with working capital as part of the capital factor

**Hydro One Networks Inc.**
**Implementation of Decision in EB-2021-0110**

**Transmission In-Service Additions**

| ($ millions) | Supporting Reference | Hydro One Proposed | | | | | OEB Decision Impact | | | | | OEB Approved | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | 2023 | 2024 | 2025 | 2026 | 2027 | 2023 | 2024 | 2025 | 2026 | 2027 | 2023 | 2024 | 2025 | 2026 | 2027 |
| In-Service Additions | Exhibit O-02-01, Attachment 5<br>Supporting details below | 1,404.5 | 1,393.2 | 1,795.6 | 1,347.5 | 1,683.8 | (70.5) | (129.0) | (163.8) | (134.9) | (171.2) | 1,334.1 | 1,264.2 | 1,631.8 | 1,212.7 | 1,512.5 |

OEB Decision Impact Supporting Details

| Adjustments | Settlement Proposal Reference | 2023 | 2024 | 2025 | 2026 | 2027 |
|---|---|---|---|---|---|---|
| Overall Capital reductions | Part C, Issue 9 | (70.5) | (129.0) | (163.8) | (134.9) | (171.2) |

**Table 1a – Tx Charge Determinants Forecast**
**(12-month average peak in MW)**

| Year | Network | Line Connection | Transformation Connection |
|---|---|---|---|
| 2023 | 19,334 | 18,768 | 15,965 |
| 2024 | 19,384 | 18,816 | 16,006 |
| 2025 | 19,139 | 18,579 | 15,805 |
| 2026 | 19,058 | 18,502 | 15,739 |
| 2027 | 19,128 | 18,569 | 15,796 |

**Table 1b – Tx Charge Determinants Forecast**
**(12-month sum of peak in MW)**

| Year | Network | Line Connection | Transformation Connection |
|---|---|---|---|
| 2023 | 232,012 | 225,213 | 191,579 |
| 2024 | 232,611 | 225,790 | 192,070 |
| 2025 | 229,665 | 222,952 | 189,656 |
| 2026 | 228,698 | 222,021 | 188,864 |
| 2027 | 229,538 | 222,830 | 189,552 |

Note. All figures are weather-normal.

# Hydro One Networks Inc.

Implementation of Decision in EB-2021-0110

### Table 1 - 2023 Revenue Requirement by Rate Pool

| | Supporting Schedule | 2023 Rate Pool Revenue Requirement ($ Million) | | | |
|---|---|---|---|---|---|
| | | **Network** | **Line Connection** | **Transformation Connection** | **Uniform Transmission Rates Revenue Requirement** |
| OM&A | *1.1 (Note1)* | $212.0 | $40.9 | $106.4 | $359.2 |
| Property Taxes and Rights Payments | *1.1 (Note1)* | $46.7 | $8.1 | $20.3 | $75.1 |
| Depreciation of Fixed Assets | *1.2 (Note2)* | $286.4 | $42.0 | $152.7 | $481.1 |
| Capitalized Depreciation | *1.2 (Note2)* | ($9.1) | ($1.6) | ($4.1) | ($14.8) |
| Asset Removal Costs | *1.2 (Note2)* | $35.4 | $6.0 | $16.0 | $57.4 |
| OPEB Amortization | *1.2 (Note2)* | $4.5 | $0.9 | $2.3 | $7.6 |
| Return on Debt | *1.4* | $210.1 | $36.5 | $91.6 | $338.1 |
| Return on Equity | *1.4* | $301.3 | $52.3 | $131.3 | $484.9 |
| Income Taxes | *1.5* | $27.2 | $4.7 | $11.9 | $43.8 |
| **Base Revenue Requirement** | | **$1,114.4** | **$189.8** | **$528.2** | **$1,832.5** |
| External Revenue | *1.6* | ($24.8) | ($4.2) | ($11.8) | ($40.8) |
| **Total Revenue Requirement** | | **$1,089.5** | **$185.6** | **$516.5** | **$1,791.6** |
| WMS Revenue | *Note 3* | $0.00 | $0.00 | ($0.03) | ($0.03) |
| Export Revenue | *1.7* | ($37.4) | $0.0 | $0.0 | ($37.4) |
| Regulatory Assets | *1.8* | ($13.3) | ($2.4) | ($6.8) | ($22.5) |
| LVSG Credit | *2.7* | $0.0 | $0.0 | $16.3 | $16.3 |
| **Total Rates Revenue Requirement** | | **$1,038.9** | **$183.2** | **$525.9** | **$1,748.0** |

*Note 1: Included in OEB Approved 2023 OMA total in Schedule 1.1.*
*Note 2: Included in OEB Approved 2023 Depreciation total in Schedule 1.2.*
*Note 3: OEB Approved WMS revenue per Attachment 1, Schedule 1.0*

### Table 2 - Percentage Split of Base Revenue Requirement by Transmission Rate Pool

| | Network | Line Connection | Transformation Connection | Total |
|---|---|---|---|---|
| 2023 Base Revenue Requirement | **$1,114.4** | **$189.8** | **$528.2** | **$1,832.5** |
| Percentage Split by Rate Pool | 61% | 10% | 29% | 100% |

### Table 3 - 2024 Detailed Revenue Requirement by Rate Pool

| | Rate Pool Revenue Requirement ($ Millions) | | | |
|---|---|---|---|---|
| | **Network** | **Line Connection** | **Transformation Connection** | **Total** |
| Percentage Split by Rate pool | 61% | 10% | 29% | 100% |
| **Total Revenue Requirement** | **$1,179.0** | **$200.9** | **$558.9** | **$1,938.7** |
| External Revenue | ($22.5) | ($3.8) | ($10.6) | ($36.9) |
| WMS Revenue | $0.0 | $0.0 | ($0.02) | ($0.02) |
| Export Revenue | ($37.1) | $0.0 | $0.0 | ($37.1) |
| Regulatory Assets | - | - | - | - |
| LVSG Credit | $0.0 | $0.0 | $17.4 | $17.4 |
| **Total Rates Revenue Requirement** | **$1,119.4** | **$197.0** | **$565.7** | **$1,882.1** |

# Hydro One Networks Inc.

Implementation of Decision in EB-2021-0110

### Table 4 - 2025 Detailed Revenue Requirement by Rate Pool

| | Rate Pool Revenue Requirement ($ Millions) | | | |
|---|---|---|---|---|
| | **Network** | **Line Connection** | **Transformation Connection** | **Total** |
| Percentage Split by Rate pool | 61% | 10% | 29% | 100% |
| **Total Revenue Requirement** | **$1,227.3** | **$209.1** | **$581.8** | **$2,018.2** |
| External Revenue | ($22.6) | ($3.8) | ($10.7) | ($37.1) |
| WMS Revenue | - | - | - | - |
| Export Revenue | ($37.3) | $0.0 | $0.0 | ($37.3) |
| Regulatory Assets | - | - | - | - |
| LVSG Credit | $0.0 | $0.0 | $18.3 | $18.3 |
| **Total Rates Revenue Requirement** | **$1,167.5** | **$205.2** | **$589.4** | **$1,962.1** |

### Table 5 - 2026 Detailed Revenue Requirement by Rate Pool

| | Rate Pool Revenue Requirement ($ Millions) | | | |
|---|---|---|---|---|
| | **Network** | **Line Connection** | **Transformation Connection** | **Total** |
| Percentage Split by Rate pool | 61% | 10% | 29% | 100% |
| **Total Revenue Requirement** | **$1,284.3** | **$218.8** | **$608.8** | **$2,111.8** |
| External Revenue | ($22.4) | ($3.8) | ($10.6) | ($36.9) |
| WMS Revenue | - | - | - | - |
| Export Revenue | ($37.2) | $0.0 | $0.0 | ($37.2) |
| Regulatory Assets | - | - | - | - |
| LVSG Credit | $0.0 | $0.0 | $19.3 | $19.3 |
| **Total Rates Revenue Requirement** | **$1,224.6** | **$215.0** | **$617.4** | **$2,056.9** |

### Table 6 - 2027 Detailed Revenue Requirement by Rate Pool

| | Rate Pool Revenue Requirement ($ Millions) | | | |
|---|---|---|---|---|
| | **Network** | **Line Connection** | **Transformation Connection** | **Total** |
| Percentage Split by Rate pool | 61% | 10% | 29% | 100% |
| **Total Revenue Requirement** | **$1,326.7** | **$226.0** | **$628.9** | **$2,181.6** |
| External Revenue | ($23.1) | ($3.9) | ($10.9) | ($37.9) |
| WMS Revenue | - | - | - | - |
| Export Revenue | ($37.2) | $0.0 | $0.0 | ($37.2) |
| Regulatory Assets | - | - | - | - |
| LVSG Credit | $0.0 | $0.0 | $19.8 | $19.8 |
| **Total Rates Revenue Requirement** | **$1,266.4** | **$222.1** | **$637.7** | **$2,126.2** |

# Uniform Transmission Rates and Revenue Disbursement Allocators

**Effective April 1, 2022**

| Transmitter | Revenue Requirement ($) | | | |
|---|---|---|---|---|
| | Network | Line Connection | Transformation Connection | Total |
| CNPI | $2,837,776 | $489,867 | $1,319,558 | $4,647,201 |
| FNEI | $4,877,864 | $842,035 | $2,268,193 | $7,988,092 |
| Hydro One | $1,150,125,339 | $198,538,821 | $534,805,167 | $1,883,469,327 |
| HOSSM | $25,907,166 | $4,472,189 | $12,046,762 | $42,426,118 |
| B2MLP | $33,652,083 | $0 | $0 | $33,652,083 |
| NRLP | $8,281,339 | $0 | $0 | $8,281,339 |
| NextBridge | $53,100,835 | $0 | $0 | $53,100,835 |
| WPLP | $27,303,816 | $0 | $0 | $27,303,816 |
| All Transmitters | $1,306,086,218 | $204,342,912 | $550,439,680 | $2,060,868,811 |

| Transmitter | Total Annual Charge Determinants (MW)* | | | |
|---|---|---|---|---|
| | Network | Line Connection | Transformation Connection | |
| CNPI | 522.894 | 549.258 | 549.258 | |
| FNEI | 230.410 | 248.860 | 73.040 | |
| Hydro One | 234,736.371 | 228,350.406 | 194,599.235 | |
| HOSSM | 3,498.236 | 2,734.624 | 635.252 | |
| B2MLP | 0.000 | 0.000 | 0.000 | |
| NRLP | 0.000 | 0.000 | 0.000 | |
| NextBridge | 0.000 | 0.000 | 0.000 | |
| WPLP | 14.468 | 0.000 | 0.000 | |
| All Transmitters | 239,002.379 | 231,883.148 | 195,856.785 | |

| Transmitter | Uniform Rates and Revenue Allocators | | | |
|---|---|---|---|---|
| | Network | Line Connection | Transformation Connection | |
| Uniform Transmission Rates ($/kW-Month) | **5.46** | **0.88** | **2.81** | |
| | | | | |
| **CNPI** Allocation Factor | **0.00217** | **0.00240** | **0.00240** | |
| **FNEI** Allocation Factor | **0.00373** | **0.00412** | **0.00412** | |
| **Hydro One** Allocation Factor | **0.88058** | **0.97159** | **0.97159** | |
| **HOSSM** Allocation Factor | **0.01984** | **0.02189** | **0.02189** | |
| **B2MLP** Allocation Factor | **0.02577** | **0.00000** | **0.00000** | |
| **NRLP** Allocation Factor | **0.00634** | **0.00000** | **0.00000** | |
| **NextBridge** Allocation Factor | **0.04066** | **0.00000** | **0.00000** | |
| **WPLP** Allocation Factor | **0.02091** | **0.00000** | **0.00000** | |
| Total of Allocation Factors | 1.00000 | 1.00000 | 1.00000 | |

* The sum of 12 monthly charge determinants for the year.

*Note 1: CNPI Revenue Requirement and Charge Determinants per OEB Decision and Order EB-2015-0354 dated January 14,2016.*
*Note 2: FNEI Revenue Requirement and Charge Determinants per OEB Order EB-2016-0231 dated January 18, 2018.*
*Note 3: Hydro One Revenue Requirement and Charge Determinants per OEB Decision and Order EB-2021-0185, dated December 16, 2021.*
*Note 4: HOSSM Revenue Requirement and Charge Determinants per OEB Decision and Order EB-2021-0186 dated December 16, 2021.*
*Note 5: B2M LP Revenue Requirement per OEB Decision and Order EB-2021-0187 dated December 16, 2021.*
*Note 6: NRLP Revenue Requirement per OEB Decision and Order EB-2021-0188 dated December 16, 2021.*
*Note 7: NextBridge Revenue Requirement per OEB Decision and Order EB-2021-0150 dated August 19, 2021.*
*Note 8: WPLP Revenue Requirement and Charge Determinants per OEB Decision and Order EB-2021-0134 dated December 2, 2021.*
*Note 9: The revenue requirements of the licensed electricity transmitters are allocated to the three transmission rate pools on the same basis as is used for Hydro One. The total revenue requirements for each of the three transmission rate pools are then divided by the total charge determinants for each rate pool to establish the UTRs to two decimal places. The IESO uses the revenue collected from the UTRs to settle on a monthly basis with all rate-regulated transmitters using the revenue allocation factors.*
*Note 10: The allocation factors for each transmitter other than Hydro One are calculated by dividing each transmitter's revenue requirement assigned to each transmission rate pool by the total transmitters revenue requirement for each rate pool. The allocation factors are rounded to five decimal places for each transmitter. The sum of these individual transmitter allocation factors is then deducted from 1.0 to determine the allocation factor for Hydro One.*
*Note 11: Calculated data in shaded cells.*

# 2022 ONTARIO UNIFORM TRANSMISSION RATE SCHEDULES

## EB-2022-0084

**The rates contained herein shall be implemented effective April 1, 2022**

Issued: April 7, 2022
Ontario Energy Board

## TERMS AND CONDITIONS

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

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

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

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

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

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

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

**(H) EMBEDDED CONNECTION POINT** In accordance with Chapter 6 of the Market Rules, the IESO may permit a Metered Market Participant, as defined in the Market Rules, to register a metering installation that is located at the embedded connection point for the purpose of recording transactions in the IESO-administered markets. (The Market Rules define an embedded connection point as a point of connection between load or generation facility and distribution system). In special situations, a metering installation at the embedded connection point that is used to settle energy market charges may also be used to settle transmission service charges, if there is no metering installation at the point of connection of a distribution feeder to the Transmission Delivery Point. In above situations: •The Transmission Customer may utilize the metering installation at the embedded connection point, including all embedded generation and load connected to that point, to satisfy the requirements described in Section (F) above provided that the same metering installation is also used to satisfy the requirement for energy transactions in the IESO- administered market. •The Transmission Customer shall provide the Metering Registry information for the metering installation at the embedded connection point, including all embedded generation and load connected to that point, in accordance with the requirements described in Section (F) above so that the IESO can calculate the monthly transmission service charges payable by the Transmission Customer.

## RATE SCHEDULE: (PTS) PROVINCIAL TRANSMISSION RATES

***APPLICABILITY:***

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

| | Monthly Rate ($ per kW) |
|---|---|
| **Network Service Rate (PTS-N):** | **5.46** |
| $ Per kW of Network Billing Demand [1,2] | |
| **Line Connection Service Rate (PTS-L):** | **0.88** |
| $ Per kW of Line Connection Billing Demand [1,3] | |
| **Transformation Connection Service Rate (PTS-T):** | **2.81** |
| $ Per kW of Transformation Connection Billing Demand [1,3,4] | |

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

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

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

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

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

***TERMS AND CONDITIONS OF SERVICE:***

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

## RATE SCHEDULE: (ETS) EXPORT TRANSMISSION SERVICE

***APPLICABILITY:***

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

| | Hourly Rate |
|---|---|
| **Export Transmission Service Rate (ETS):** | $1.85 / MWh |

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

***TERMS AND CONDITIONS OF SERVICE:***

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

# Hydro One Networks Inc.

Implementation of Decision in EB-2021-0110

## 2023 Interim Uniform Transmission Rates and Revenue Disbursement Allocators (Updated for H1N's 2023 Charge Determinants and Revenue Requirement)

**Effective January 1, 2023 to December 31, 2023**

| Transmitter | Revenue Requirement ($) | | | |
|---|---|---|---|---|
| | Network | Line Connection | Transformation Connection | Total |
| CNPI | $2,762,043 | $486,989 | $1,398,169 | $4,647,201 |
| FNEI | $4,747,687 | $837,087 | $2,403,319 | $7,988,092 |
| HOSSM | $25,215,773 | $4,445,910 | $12,764,435 | $42,426,118 |
| H1N | $1,038,905,195 | $183,174,204 | $525,902,471 | $1,747,981,870 |
| B2MLP | $33,652,083 | $0 | $0 | $33,652,083 |
| NRLP | $8,281,339 | $0 | $0 | $8,281,339 |
| NextBridge | $53,100,835 | $0 | $0 | $53,100,835 |
| WPLP | $27,303,816 | $0 | $0 | $27,303,816 |
| All Transmitters | $1,193,968,771 | $188,944,190 | $542,468,393 | $1,925,381,354 |

| Transmitter | Total Annual Charge Determinants (MW)* | | | |
|---|---|---|---|---|
| | Network | Line Connection | Transformation Connection | |
| CNPI | 522.894 | 549.258 | 549.258 | |
| FNEI | 230.410 | 248.860 | 73.040 | |
| HOSSM | 3,498.236 | 2,734.624 | 635.252 | |
| H1N | 232,011.781 | 225,212.751 | 191,579.069 | |
| B2MLP | 0.000 | 0.000 | 0.000 | |
| NRLP | 0.000 | 0.000 | 0.000 | |
| NextBridge | 0.000 | 0.000 | 0.000 | |
| WPLP | 14.468 | 0.000 | 0.000 | |
| All Transmitters | 236,277.789 | 228,745.493 | 192,836.619 | |

| Transmitter | Uniform Rates and Revenue Allocators | | | |
|---|---|---|---|---|
| | Network | Line Connection | Transformation Connection | |
| Uniform Transmission Rates ($/kW-Month) | **5.05** | **0.83** | **2.81** | |
| | | | | |
| **CNPI** Allocation Factor | **0.00231** | **0.00258** | **0.00258** | |
| **FNEI** Allocation Factor | **0.00398** | **0.00443** | **0.00443** | |
| **HOSSM** Allocation Factor | **0.02112** | **0.02353** | **0.02353** | |
| **H1N** Allocation Factor | **0.87012** | **0.96946** | **0.96946** | |
| **B2MLP** Allocation Factor | **0.02819** | **0.00000** | **0.00000** | |
| **NRLP** Allocation Factor | **0.00694** | **0.00000** | **0.00000** | |
| **NextBridge** Allocation Factor | **0.04447** | **0.00000** | **0.00000** | |
| **WPLP** Allocation Factor | **0.02287** | **0.00000** | **0.00000** | |
| Total of Allocation Factors | 1.00000 | 1.00000 | 1.00000 | |

* The sum of 12 monthly charge determinants for the year.

*Note 1: H1N Rates Revenue Requirement as per Schedule 2.2, Table 1 and Charge Determinants as per Schedule 2.1.*

*Note 2: Revenue Requirements and Charge Determinants for all other transmitters as per the 2022 UTR Update (EB-2022-0084 issued April 7, 2022).*

*Note 3: Calculated data in shaded cells.*

# 2023 PROPOSED ONTARIO UNIFORM TRANSMISSION RATE SCHEDULES

## EB-2022-XXXX

**The rate schedules contained herein shall be effective January 1, 2023**

Issued: Month, Year
Ontario Energy Board

## TERMS AND CONDITIONS

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

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

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

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

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

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

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

(H) EMBEDDED CONNECTION POINT In accordance with Chapter 6 of the Market Rules, the IESO may permit a Metered Market Participant, as defined in the Market Rules, to register a metering installation that is located at the embedded connection point for the purpose of recording transactions in the IESO-administered markets. (The Market Rules define an embedded connection point as a point of connection between load or generation facility and distribution system). In special situations, a metering installation at the embedded connection point that is used to settle energy market charges may also be used to settle transmission service charges, if there is no metering installation at the point of connection of a distribution feeder to the Transmission Delivery Point. In above situations: •The Transmission Customer may utilize the metering installation at the embedded connection point, including all embedded generation and load connected to that point, to satisfy the requirements described in Section (F) above provided that the same metering installation is also used to satisfy the requirement for energy transactions in the IESO- administered market. •The Transmission Customer shall provide the Metering Registry information for the metering installation at the embedded connection point, including all embedded generation and load connected to that point, in accordance with the requirements described in Section (F) above so that the IESO can calculate the monthly transmission service charges payable by the Transmission Customer.

## RATE SCHEDULE: (PTS) PROVINCIAL TRANSMISSION RATES

APPLICABILITY:

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

| | Monthly Rate ($ per kW) |
|---|---|
| Network Service Rate (PTS-N):<br>$ Per kW of Network Billing Demand [1,2] | 5.05 |
| Line Connection Service Rate (PTS-L):<br>$ Per kW of Line Connection Billing Demand [1,3] | 0.83 |
| Transformation Connection Service Rate (PTS-T):<br>$ Per kW of Transformation Connection Billing Demand [1,3,4] | 2.81 |

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

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

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

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

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

TERMS AND CONDITIONS OF SERVICE:

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

RATE SCHEDULE: (ETS) EXPORT TRANSMISSION SERVICE

APPLICABILITY:

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

| | Hourly Rate |
|---|---|
| Export Transmission Service Rate (ETS): | $1.85 / MWh |

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

TERMS AND CONDITIONS OF SERVICE:

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

# Hydro One Networks Inc.

Implementation of Decision in EB-2021-0110

**Low Voltage Switchgear (LVSG) Credit 2023-2027**

| Year | Charge Determinant (MW) | Transformation Pool Revenue Requirement Before LVSG Credit ($M) | Rate Before LVSG Credit ($/kw/month) | Total Annual NCP Demand for Toronto Hydro and Hydro Ottawa (MW) | LVS Proportion (%) | Final Annual LVSG Credit ($M) |
|---|---|---|---|---|---|---|
| | *(Note 1)* | *(Note 2)* | | *(Note 3)* | *(Note 4)* | |
| | (A) | (B) | (C) = (B)/(A) | (D) | (E) | (F) = (C)x(D)x(E) |
| **2023** | 191,579 | $509.7 | $2.66 | 32,150 | 19.0% | $16.3 |
| **2024** | 192,070 | $548.2 | $2.85 | 32,167 | 19.0% | $17.4 |
| **2025** | 189,656 | $571.1 | $3.01 | 32,027 | 19.0% | $18.3 |
| **2026** | 188,864 | $598.1 | $3.17 | 31,998 | 19.0% | $19.3 |
| **2027** | 189,552 | $617.9 | $3.26 | 31,892 | 19.0% | $19.8 |

*Note 1: Per Schedule 2.1*
*Note 2: Equals Total Rates Revenue Requirement for Transformation Connection Pool excluding LVSG Credit, as per information in Schedule 2.2*
*Note 3: Sum of Toronto Hydro and Hydro Ottawa total annual NCP Demand consistent with OEB approved load forecast for 2023 to 2027*
*Note 4: Per EB-2021-0110, Exhibit H, Tab 1, Schedule 3, page 7*

# Hydro One Networks Inc.

Implementation of Decision in EB-2021-0110

## 2023 Bill Impacts on Transmission-Connected and Distribution-Connected Customers

### Table 1 - Average Bill Impacts on Transmission and Distribution-connected Customers

| | 2022 | 2023 |
|---|---|---|
| Revenue Requirement ($ Millions) | 1,816.2 | 1,832.5 |
| Adjustments to Revenue Requirement ($ Millions) (Note 1,3) | 67.3 | -40.9 |
| Rates Revenue Requirement ($ millions) (Note 1) | 1,883.5 | 1,791.5 |
| % Increase in Rates Revenue Requirement over prior year | | -4.9% |
| % Impact of load forecast change (Note 4) | | 1.4% |
| **Net Impact on Average Transmission Rates (Note 2)** | | -3.2% |
| Transmission as a % of Tx-connected customer's Total Bill | | 7.6% |
| **Estimated Average Bill Impact** | | -0.2% |
| Transmission as a % of Dx-connected customer's Total Bill | | 6.2% |
| **Estimated Average Bill Impact** | | -0.2% |

Note 1: Adjustments include non-rate revenues, export revenues, disposition of regulatory accounts and low voltage switchgear credit. For purpose of estimating rate impacts, adjustments also include historical misallocated Future Tax Savings amounts being recovered in 2022 (+$87.1) and 2023 (+$43.5) per the OEB Decision in proceeding EB-2020-0194. The 2022 rates revenue requirement of $1,883.5 million was approved in EB-2021-0185 on December 16, 2021.
Note 2: The calculation of net impact on transmission rates accounts for Hydro One's revenue disbursement allocation factor of 91.4% as approved for 2022 UTR Revenue Requirement (EB-2022-0084 issued April 7, 2022).
Note 3: The Adjustments to Revenue Requirement reflects the $27.5M credit for External Revenue Variances in 2023.
Note 4: The Impact of load forecast change includes a 1.2% impact in 2023 due to the correction to approved 2022 load forecast charge determinants as per the OEB Decision in proceeding EB-2019-0082, dated April 23, 2020.

# Hydro One Networks Inc.

Implementation of Decision in EB-2021-0110

### 2023 Bill Impacts on Transmission-Connected and Distribution-Connected Customers

### Table 2 - Typical Medium Density (R1) Residential Customer Bill Impacts

| | Typical R1 Residential Customer | | |
|---|---|---|---|
| | **400 kWh** | **750 kWh** | **1,800 kWh** |
| Total Bill as of Jan 1, 2022[1] | $86.17 | $130.55 | $263.67 |
| RTSR included in 2022 R1 Customer's Bill (Based on July 1, 2021 UTR) | $7.70 | $14.45 | $34.67 |
| *Estimated 2022 Monthly RTSR [2]* | $8.13 | $15.25 | $36.59 |
| **2022 change in Monthly Bill** | **$0.43** | **$0.80** | **$1.93** |
| *2022 change as a % of total bill* | *0.5%* | *0.6%* | *0.7%* |
| *Estimated 2023 Monthly RTSR [3]* | $7.87 | $14.76 | $35.42 |
| **2023 change in Monthly Bill** | **($0.26)** | **($0.49)** | **($1.17)** |
| *2023 change as a % of total bill* | *-0.3%* | *-0.4%* | *-0.4%* |

[1]Total bill including HST, based on time-of-use commodity prices effective May 1, 2021 and distribution rates effective January 1, 2022 approved per Distribution Rate Order EB-2021-0032, dated December 14, 2021 (includes impacts of all components of the Fair Hydro Plan).

[2]The estimated 2022 Monthly RTSRs reflect Hydro One's 2022 TX Rates Revenue Requirement as included in 2022 Uniform Transmission Rate Schedules issued December 16, 2021 (EB-2021-0276).

[3]The impact on RTSR is assumed to be the net impact on average transmission rates, as per Table 1 above, adjusted for Hydro One's total revenue disbursement allocator per 2022 UTR Order (EB-2022-0082 dated April 7, 2022)

### Table 3 - Typical General Service Energy less than 50 kW (GSe < 50 kW) Customer Bill Impacts

| | GSe Customer Monthly Bill | | |
|---|---|---|---|
| | **1,000 kWh** | **2,000 kWh** | **15,000 kWh** |
| Total Bill as of Jan 1, 2022[1] | $225.11 | $416.29 | $2,901.63 |
| RTSR included in 2022 GSe Customer's Bill (Based on July 1, 2021 UTR) | $15.34 | $30.69 | $230.16 |
| *Estimated 2022 Monthly RTSR [2]* | $16.20 | $32.39 | $242.94 |
| **2022 change in Monthly Bill** | **$0.85** | **$1.70** | **$12.78** |
| *2022 change as a % of total bill* | *0.4%* | *0.4%* | *0.4%* |
| *Estimated 2023 Monthly RTSR [3]* | $15.68 | $31.35 | $235.15 |
| **2023 change in Monthly Bill** | **($0.52)** | **($1.04)** | **($7.80)** |
| *2023 change as a % of total bill* | *-0.2%* | *-0.2%* | *-0.3%* |

[1]Total bill including HST, based on time-of-use commodity prices effective May 1, 2021 and distribution rates effective January 1, 2022 approved per Distribution Rate Order EB-2021-0032, dated December 14, 2021(includes impacts of all components of the Fair Hydro Plan).

[2]The estimated 2022 Monthly RTSRs reflect Hydro One's 2022 TX Rates Revenue Requirement as included in 2022 Uniform Transmission Rate Schedules issued December 16, 2021 (EB-2021-0276).

[3]The impact on RTSR is assumed to be the net impact on average transmission rates, as per Table 1 above, adjusted for Hydro One's total revenue disbursement allocator per 2022 UTR Order (EB-2022-0082 dated April 7, 2022)

# HYDRO ONE NETWORKS INC.
# WHOLESALE METER SERVICE
# AND EXIT FEE SCHEDULE

***APPLICABILITY:***

This fee schedule is applicable to the *metered market participants** that are transmission customers of Hydro One Networks ("Networks") and to *metered market participants* that are customers of a Local Distribution Company ("LDC") that is connected to the transmission system owned by Networks.

* The terms and acronyms that are italicized in this schedule have the meanings ascribed thereto in Chapter 11 of the Market Rules for the Ontario Electricity Market.

## a) Fee for Wholesale Meter Service

The *metered market participant* in respect of a *load facility* (including customers of an LDC) shall be required to pay an annual fee of $7,900 for each *meter point* that is under the transitional arrangement for a *metering installation* in accordance with Section 3.2 of Chapter 6 of the Market Rules for the Ontario Electricity Market.

This Wholesale Meter Service annual fee shall remain in place until all the remaining meter points exit the transitional arrangement.

## b) Fee for Exit from Transitional Arrangement

The *metered market participant* in respect of a *load facility* (including customers of an LDC) or a *generation facility* may exit from the transitional arrangement for a *metering installation* upon payment of a one-time exit fee of $ 5,200 per *meter point*.

# ATTACHMENT 2

## DISTRIBUTION SUPPORTING SCHEDULES

**Hydro One Networks Inc.**
**Implementation of Decision in EB-2021-0110**

**Revenue Requirement Summary - Distribution**

| ($ millions) | Supporting Reference | Hydro One Proposed 2023 | 2024 | 2025 | 2026 | 2027 | OEB Decision Impact 2023 | 2024 | 2025 | 2026 | 2027 | OEB Approved 2023 | 2024 | 2025 | 2026 | 2027 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| OM&A | Exhibit 1.1 | 634.4 | 646.4 | 658.7 | 671.2 | 684.0 | (16.4) | (17.6) | (18.9) | (20.2) | (21.6) | 618.0 | 628.8 | 639.8 | 651.0 | 662.4 |
| Depreciation | Exhibit 1.2 | 465.1 | 488.2 | 531.7 | 569.4 | 606.9 | (3.7) | (6.9) | (17.0) | (23.5) | (28.4) | 461.4 | 481.3 | 514.7 | 545.9 | 578.6 |
| Return on Debt | Exhibit 1.4 | 220.0 | 234.9 | 252.0 | 268.8 | 283.4 | 1.5 | (1.3) | (4.5) | (7.7) | (10.6) | 221.5 | 233.6 | 247.5 | 261.1 | 272.9 |
| Return on Equity | Exhibit 1.4 | 313.4 | 334.6 | 359.1 | 382.9 | 403.8 | 2.2 | (1.7) | (6.4) | (10.9) | (15.0) | 315.6 | 332.9 | 352.7 | 372.0 | 388.8 |
| Working Capital Adjustment | Exhibit 1.7 | | 0.2 | 0.4 | 0.6 | 0.8 | | (0.0) | (0.0) | (0.0) | 0.0 | | 0.2 | 0.4 | 0.6 | 0.8 |
| Productivity Factor | | | (4.9) | (10.2) | (15.8) | (21.9) | | (2.2) | (4.4) | (6.7) | (9.0) | | (7.1) | (14.5) | (22.5) | (30.9) |
| RCI Annual Update | | | | | | | | | | | | | | | | |
| Regulatory Tax | Exhibit 1.5 | 36.2 | 53.9 | 40.4 | 57.8 | 67.6 | 3.6 | 5.4 | 7.1 | 6.2 | 4.5 | 39.8 | 59.3 | 47.6 | 64.0 | 72.1 |
| **Service Revenue Requirement** | | **1,669.1** | **1,753.3** | **1,832.2** | **1,934.8** | **2,024.6** | **(12.8)** | **(24.3)** | **(44.0)** | **(62.6)** | **(80.0)** | **1,656.3** | **1,729.0** | **1,788.2** | **1,872.2** | **1,944.7** |
| Deduct: External Revenue | Exhibit 1.6 | (46.4) | (46.5) | (46.5) | (46.0) | (46.1) | 2.8 | 2.6 | 2.4 | 2.2 | 1.9 | (43.6) | (43.9) | (44.1) | (43.8) | (44.2) |
| **Base Revenue Requirement** | | **1,622.6** | **1,706.9** | **1,785.7** | **1,888.8** | **1,978.5** | **(9.9)** | **(21.7)** | **(41.6)** | **(60.4)** | **(78.1)** | **1,612.7** | **1,685.1** | **1,744.1** | **1,828.4** | **1,900.5** |

**Hydro One Networks Inc.**
**Implementation of Decision in EB-2021-0110**

**Distribution OM&A**

| | | Hydro One Proposed | | | | | OEB Decision Impact | | | | | OEB Approved | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| *($ millions)* | **Supporting Reference** | **2023** | **2024** | **2025** | **2026** | **2027** | **2023** | **2024** | **2025** | **2026** | **2027** | **2023** | **2024** | **2025** | **2026** | **2027** |
| OM&A | Exhibit O-01-02, Table 3 | 628.9 | 640.8 | 653.0 | 665.4 | 678.0 | (10.9) | (12.0) | (13.2) | (14.4) | (15.6) | 618.0 | 628.8 | 639.8 | 651.0 | 662.4 |
| Proposed PCB Treatment | | 5.5 | 5.6 | 5.7 | 5.8 | 5.9 | (5.5) | (5.6) | (5.7) | (5.8) | (5.9) | - | - | - | - | - |
| Total OM&A [1] | See supporting details below | 634.4 | 646.4 | 658.7 | 671.2 | 684.0 | (16.4) | (17.6) | (18.9) | (20.2) | (21.6) | 618.0 | 628.8 | 639.8 | 651.0 | 662.4 |

*OEB Decision Impact Supporting Details*

| **Adjustments** | **Settlement Proposal Reference** | **2023** |
|---|---|---|
| PCB Shift from OM&A to Dep. | Part C, Issue 22 | (5.5) |
| 2% OM&A Reduction [2] | Part C, Issue 19 | (12.6) |
| Overhead Capitalization Update | Part C, Issue 16 | 1.7 |
| **Total Adjustments** | | **(16.4)** |

Note [1]: The Total OM&A line includes the Proposed PCB Treatment for revenue requirement purposes as proposed by Hydro One
Note [2]: 2% OM&A reduction is applied on the $628.9M figure

**Hydro One Networks Inc.**
**Implementation of Decision in EB-2021-0110**

**Distribution Rate Base and Depreciation**

| | | Hydro One Proposed | | | | | OEB Decision Impact | | | | | OEB Approved | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| *($ millions)* | **Supporting Reference** | **2023** | **2024** | **2025** | **2026** | **2027** | **2023** | **2024** | **2025** | **2026** | **2027** | **2023** | **2024** | **2025** | **2026** | **2027** |
| Rate Base | See supporting details below | 9,394.7 | 10,031.4 | 10,764.2 | 11,477.9 | 12,104.7 | 65.4 | (52.4) | (191.7) | (325.3) | (448.9) | 9,460.0 | 9,979.0 | 10,572.5 | 11,152.6 | 11,655.7 |
| Total Depreciation & Amortization Expenses | Exhibit E-08-01, Attachment 2 | 470.6 | 493.7 | 532.7 | 569.4 | 606.9 | (9.2) | (12.4) | (17.9) | (23.5) | (28.4) | 461.4 | 481.3 | 514.7 | 545.9 | 578.6 |
| Proposed PCB Treatment | Exhibit D-01-01 | (5.5) | (5.4) | (1.0) | - | - | 5.5 | 5.4 | 1.0 | - | - | - | - | - | - | - |
| Depreciation & Amortization for Recovery [1] | Exhibit O-01-02, Attachment 8 | 465.1 | 488.2 | 531.7 | 569.4 | 606.9 | (3.7) | (6.9) | (17.0) | (23.5) | (28.4) | 461.4 | 481.3 | 514.7 | 545.9 | 578.6 |

Note [1] The Depreciation line reflected the Proposed PCB Treatment for revenue requirement purposes, as further explained in Section 4 of Exhibit D-01-01

*OEB Decision Impact Supporting Details*

**Detailed Calculation**

| | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Working Capital Adjustment | | | | | | | | | | | | | | | |
| Rate Base Details | | | | | | | | | | | | | | | |
| Utility plant (average) | | | | | | | | | | | | | | | |
| Gross plant at cost | 14,834.1 | 15,702.6 | 16,684.5 | 17,681.2 | 18,639.4 | 113.8 | (4.3) | (147.8) | (290.7) | (428.5) | 14,947.9 | 15,698.4 | 16,536.7 | 17,390.5 | 18,210.9 |
| Less: Accumulated depreciation | (5,691.2) | (5,926.0) | (6,177.7) | (6,464.0) | (6,798.5) | (46.4) | (46.6) | (42.4) | (33.1) | (18.9) | (5,737.6) | (5,972.6) | (6,220.1) | (6,497.1) | (6,817.4) |
| Add: CWIP | | | | | | | | | | | - | - | - | - | - |
| Net utility plant | 9,142.9 | 9,776.6 | 10,506.8 | 11,217.2 | 11,840.9 | 67.4 | (50.8) | (190.1) | (323.8) | (447.4) | 9,210.3 | 9,725.8 | 10,316.7 | 10,893.4 | 11,393.5 |
| Working capital | | | | | | | | | | | | | | | |
| Cash working capital | 245.7 | 248.7 | 251.2 | 254.3 | 257.3 | (2.0) | (1.6) | (1.6) | (1.5) | (1.6) | 243.8 | 247.1 | 249.6 | 252.8 | 255.7 |
| Materials & supplies inventory | 6.0 | 6.1 | 6.2 | 6.4 | 6.5 | | | | | | 6.0 | 6.1 | 6.2 | 6.4 | 6.5 |
| Total working capital | 251.7 | 254.8 | 257.4 | 260.7 | 263.8 | (2.0) | (1.6) | (1.6) | (1.5) | (1.6) | 249.8 | 253.2 | 255.8 | 259.2 | 262.2 |
| | | | | | | - | - | - | - | - | | | | | |
| Total Rate Base | 9,394.7 | 10,031.4 | 10,764.2 | 11,477.9 | 12,104.7 | 65.4 | (52.4) | (191.7) | (325.3) | (448.9) | 9,460.0 | 9,979.0 | 10,572.5 | 11,152.6 | 11,655.7 |

**HYDRO ONE NETWORKS INC.**
**DISTRIBUTION**
**Statement of Utility Rate Base**
Historical Year (2021), Bridge Year (2022) and Test Years (2023 to 2027)
Year Ending December 31
($M)

| Particulars | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 |
|---|---|---|---|---|---|---|---|
| Electric Utility Plant | | | | | | | |
| Gross plant at cost | $ 13,818.6 | $ 14,451.6 | $ 15,388.5 | $ 16,156.2 | $ 17,068.4 | $ 17,866.1 | $ 18,711.5 |
| Less: non-regulatory | (69.7) | (71.1) | (73.0) | (75.0) | (76.2) | (77.3) | (78.4) |
| Gross plant at cost for rate base | 13,748.9 | 14,380.5 | 15,315.5 | 16,081.2 | 16,992.3 | 17,788.8 | 18,633.1 |
| Less: accumulated depreciation | $ (5,345.9) | $ (5,624.4) | (5,886.8) | (6,132.1) | (6,389.3) | (6,693.8) | (7,037.7) |
| Less: non-regulatory | 27.3 | 31.3 | 35.0 | 38.7 | 42.5 | 46.4 | 50.3 |
| Accumulated depreciation for rate base | (5,318.6) | (5,593.1) | (5,851.8) | (6,093.4) | (6,346.8) | (6,647.4) | (6,987.4) |
| Net plant for rate base | $ 8,430.3 | $ 8,787.5 | 9,463.7 | 9,987.9 | 10,645.5 | 11,141.3 | 11,645.7 |
| Average net plant for rate base | | | 9,210.3 | 9,725.8 | 10,316.7 | 10,893.4 | 11,393.5 |
| Average net utility plant | | | $ 9,210.3 | $ 9,725.8 | $ 10,316.7 | $ 10,893.4 | $ 11,393.5 |
| Working Capital | | | | | | | |
| Cash working capital | | | 243.8 | 247.1 | 249.6 | 252.8 | 255.7 |
| Materials and Supplies Inventory | | | 6.0 | 6.1 | 6.2 | 6.4 | 6.5 |
| Total working capital | | | 249.8 | 253.2 | 255.8 | 259.2 | 262.2 |
| Total rate base | | | $ 9,460.0 | $ 9,979.0 | $ 10,572.5 | $ 11,152.6 | $ 11,655.7 |

2023-2027 figures are presented on a combined basis including Acquired Utilities. 2023 average rate base includes opening adjustment for Acquired Utilities.

**HYDRO ONE NETWORKS INC.**
**DISTRIBUTION**

Continuity of Property, Plant and Equipment
Historical (2021), Bridge (2022) & Test (2023-2027) Years
Year Ending December 31
Total - Gross Balances
($M)

| Line No. | Year | Opening Balance | Additions | Retirements | Sales | Transfers In/Out | Closing Balance | Average |
|---|---|---|---|---|---|---|---|---|
| | | (a) | (b) | (c) | (d) | (e) | (f) | (g) |
| Historical | | | | | | | | |
| 1 | 2021 | 13,150.9 | 710.8 | (59.5) | (7.0) | 23.3 | 13,818.6 | 13,484.7 |
| Bridge | | | | | | | | |
| 2 | 2022 | 13,818.6 | 740.5 | (108.3) | - | 0.8 | 14,451.6 | 14,135.1 |
| Test | | | | | | | | |
| 3 | 2023 | 14,651.4 | 910.0 | (173.7) | - | 0.9 | 15,388.5 | 15,020.0 |
| 4 | 2024 | 15,388.5 | 947.4 | (180.6) | - | 0.9 | 16,156.2 | 15,772.4 |
| 5 | 2025 | 16,156.2 | 1,113.1 | (201.8) | - | 0.9 | 17,068.4 | 16,612.3 |
| 6 | 2026 | 17,068.4 | 984.6 | (187.9) | - | 0.9 | 17,866.1 | 17,467.3 |
| 7 | 2027 | 17,866.1 | 1,022.6 | (178.1) | - | 0.9 | 18,711.5 | 18,288.8 |

2021-2022 figures refer only to Hydro One Distribution excluding Acquired Utilities (Norfolk, Haldimand and Woodstock).
2023-2027 figures are presented on a combined basis including Acquired Utilities.

2023 Opening Balance reflects the integration of Acquired Utilities.

# HYDRO ONE NETWORKS INC.
# DISTRIBUTION

Continuity of Property, Plant and Equipment - Accumulated Depreciation
Historical (2021), Bridge (2022) & Test (2023-2027) Years
Year Ending December 31
Total - Gross Balances
($M)

| Line No. | Year | Opening Balance | Additions | Retirements | Sales | Transfers In/Out and Other | Closing Balance | Average |
|---|---|---|---|---|---|---|---|---|
| | | (a) | (b) | (c) | (d) | (e) | (f) | (g) |
| Historical | | | | | | | | |
| 1 | 2021 | 5,048.8 | 362.7 | (59.5) | (6.4) | 0.2 | 5,345.9 | 5,197.3 |
| Bridge | | | | | | | | |
| 2 | 2022 | 5,345.9 | 386.9 | (108.3) | 0.0 | 0.0 | 5,624.4 | 5,485.1 |
| Test | | | | | | | | |
| 3 | 2023 | 5,654.8 | 405.7 | (173.7) | 0.0 | 0.0 | 5,886.8 | 5,770.8 |
| 4 | 2024 | 5,886.8 | 425.9 | (180.6) | 0.0 | 0.0 | 6,132.1 | 6,009.4 |
| 5 | 2025 | 6,132.1 | 459.1 | (201.8) | 0.0 | 0.0 | 6,389.3 | 6,260.7 |
| 6 | 2026 | 6,389.3 | 492.4 | (187.9) | 0.0 | 0.0 | 6,693.8 | 6,541.6 |
| 7 | 2027 | 6,693.8 | 522.0 | (178.1) | 0.0 | 0.0 | 7,037.7 | 6,865.8 |

2021-2022 figures refer only to Hydro One Distribution excluding Acquired Utilities (Norfolk, Haldimand and Woodstock). 2023-2027 figures are presented on a combined basis including Acquired Utilities.

2023 Opening Balance reflects the integration of Acquired Utilities.

# APPENDIX 2-BA CONTINUITY SCHEDULE

This schedule has been filed separately in MS Excel format.

**Hydro One Networks Inc.**
**Implementation of Decision in EB-2021-0110**

**Distribution Capital Expenditures**

| *($ millions)* | Supporting Reference | Hydro One Proposed | | | | | OEB Decision Impact | | | | | OEB Approved | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | 2023 | 2024 | 2025 | 2026 | 2027 | 2023 | 2024 | 2025 | 2026 | 2027 | 2023 | 2024 | 2025 | 2026 | 2027 |
| Capital expenditures | Exhibit O-01-02, Attachment 4E | 1,057.9 | 1,081.9 | 1,179.7 | 1,127.9 | 1,127.2 | (137.0) | (132.8) | (139.7) | (135.4) | (135.8) | 920.8 | 949.2 | 1,040.0 | 992.5 | 991.3 |

OEB Decision Impact Supporting Details

| Adjustments | Settlement Proposal Reference | 2023 | 2024 | 2025 | 2026 | 2027 |
|---|---|---|---|---|---|---|
| Overall capital reduction | Part C, Issue 12 | (137.0) | (132.8) | (139.7) | (135.4) | (135.8) |
| | | (137.0) | (132.8) | (139.7) | (135.4) | (135.8) |

**Hydro One Networks Inc.**
**Implementation of Decision in EB-2021-0110**

**Distribution Capital Structure and Return on Capital**

| | Hydro One Proposed | | | | | OEB Decision Impact | | | | | OEB Approved | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| *($ millions)* | **2023** | **2024** | **2025** | **2026** | **2027** | **2023** | **2024** | **2025** | **2026** | **2027** | **2023** | **2024** | **2025** | **2026** | **2027** |
| **Return on Rate Base** | | | | | | | | | | | | | | | |
| Rate Base | $ 9,394.7 | $ 10,031.4 | $ 10,764.2 | $ 11,477.9 | $ 12,104.7 | $ 65.4 | $ (52.4) | $ (191.7) | $ (325.3) | $ (448.9) | $ 9,460.0 | $ 9,979.0 | $ 10,572.5 | $ 11,152.6 | $ 11,655.7 |
| Capital Structure: | | | | | | | | | | | | | | | |
| Third-Party long-term debt | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| Deemed long-term debt | 56.0% | 56.0% | 56.0% | 56.0% | 56.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 56.0% | 56.0% | 56.0% | 56.0% | 56.0% |
| Short-term debt | 4.0% | 4.0% | 4.0% | 4.0% | 4.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 4.0% | 4.0% | 4.0% | 4.0% | 4.0% |
| Common equity | 40.0% | 40.0% | 40.0% | 40.0% | 40.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 40.0% | 40.0% | 40.0% | 40.0% | 40.0% |
| Capital Structure: | | | | | | | | | | | | | | | |
| Third-Party long-term debt | | | | | | | | | | | | | | | |
| Deemed long-term debt | $ 5,261.0 | $ 5,617.6 | $ 6,027.9 | $ 6,427.6 | $ 6,778.6 | 36.6 | (29.3) | (107.3) | (182.2) | (251.4) | $ 5,297.6 | $ 5,588.3 | $ 5,920.6 | $ 6,245.4 | $ 6,527.2 |
| Short-term debt | 375.8 | 401.3 | 430.6 | 459.1 | 484.2 | 2.6 | (2.1) | (7.7) | (13.0) | (18.0) | 378.4 | 399.2 | 422.9 | 446.1 | 466.2 |
| Common equity | 3,757.9 | 4,012.6 | 4,305.7 | 4,591.1 | 4,841.9 | 26.2 | (21.0) | (76.7) | (130.1) | (179.6) | 3,784.0 | 3,991.6 | 4,229.0 | 4,461.0 | 4,662.3 |
| | **$ 9,394.7** | **$ 10,031.4** | **$ 10,764.2** | **$ 11,477.9** | **$ 12,104.7** | **65.4** | **(52.4)** | **(191.7)** | **(325.3)** | **(448.9)** | **$ 9,460.0** | **$ 9,979.0** | **$ 10,572.5** | **$ 11,152.6** | **$ 11,655.7** |
| Allowed Return: | | | | | | | | | | | | | | | |
| Third-Party long-term debt | 4.07% | 4.07% | 4.07% | 4.07% | 4.07% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 4.07% | 4.07% | 4.07% | 4.07% | 4.07% |
| Deemed long-term debt | 4.07% | 4.07% | 4.07% | 4.07% | 4.07% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 4.07% | 4.07% | 4.07% | 4.07% | 4.07% |
| Short-term debt | 1.56% | 1.56% | 1.56% | 1.56% | 1.56% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 1.56% | 1.56% | 1.56% | 1.56% | 1.56% |
| Common equity | 8.34% | 8.34% | 8.34% | 8.34% | 8.34% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 8.34% | 8.34% | 8.34% | 8.34% | 8.34% |
| Return on Capital: | | | | | | | | | | | | | | | |
| Third-Party long-term debt | $ - | $ - | $ - | $ - | $ - | - | - | - | - | - | $ - | $ - | $ - | $ - | $ - |
| Deemed long-term debt | $ 214.1 | $ 228.6 | $ 245.3 | $ 261.6 | $ 275.9 | $ 1.5 | $ (1.2) | $ (4.4) | $ (7.5) | $ (10.3) | $ 215.6 | $ 227.4 | $ 240.9 | $ 254.1 | $ 265.6 |
| Short-term debt | $ 5.9 | $ 6.3 | $ 6.7 | $ 7.2 | $ 7.6 | 0.0 | (0.0) | (0.1) | (0.2) | (0.3) | $ 5.9 | $ 6.2 | $ 6.6 | $ 7.0 | $ 7.3 |
| Total return on debt | **$ 220.0** | **$ 234.9** | **$ 252.0** | **$ 268.8** | **$ 283.4** | **$ 1.5** | **$ (1.3)** | **$ (4.5)** | **$ (7.7)** | **$ (10.6)** | **$ 221.5** | **$ 233.6** | **$ 247.5** | **$ 261.1** | **$ 272.9** |
| | | | | | | | | | | | | | | | |
| Common equity | **$ 313.4** | **$ 334.6** | **$ 359.1** | **$ 382.9** | **$ 403.8** | **$ 2.2** | **$ (1.7)** | **$ (6.4)** | **$ (10.9)** | **$ (15.0)** | **$ 315.6** | **$ 332.9** | **$ 352.7** | **$ 372.0** | **$ 388.8** |

**HYDRO ONE NETWORKS INC.**
**DISTRIBUTION**
**Distribution Cost of Long-Term Debt Capital**
**Test Year (2023)**
**Year ending December 31**

| Line No. | Offering Date | Coupon Rate | Maturity Date | Principal Amount Offered ($Millions) | Premium Discount and Expenses ($Millions) | Net Capital Employed: Total Amount ($Millions) | Net Capital Employed: Per $100 Principal Amount (Dollars) | Effective Cost Rate | 1/1/2022 Total Amount Outstanding at 12/31/22 ($Millions) | 1/1/2023 Total Amount Outstanding at 12/31/23 ($Millions) | 1/1/2023 Avg. Monthly Averages ($Millions) | Carrying Cost ($Millions) | Projected Average Embedded Cost Rates |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 3-Jun-00 | 7.350% | 3-Jun-30 | 121.6 | 2.0 | 119.6 | 98.4 | 7.49% | 121.6 | 121.6 | 121.6 | 9.1 | |
| 2 | 22-Jun-01 | 6.930% | 1-Jun-32 | 47.7 | 0.6 | 47.1 | 98.8 | 7.03% | 47.7 | 47.7 | 47.7 | 3.4 | |
| 3 | 17-Sep-02 | 6.930% | 1-Jun-32 | 142.0 | (5.1) | 147.1 | 103.6 | 6.65% | 142.0 | 142.0 | 142.0 | 9.4 | |
| 4 | 31-Jan-03 | 6.350% | 31-Jan-34 | 74.0 | 0.6 | 73.4 | 99.2 | 6.41% | 74.0 | 74.0 | 74.0 | 4.7 | |
| 5 | 22-Apr-03 | 6.590% | 22-Apr-43 | 105.0 | 0.8 | 104.2 | 99.3 | 6.64% | 105.0 | 105.0 | 105.0 | 7.0 | |
| 6 | 25-Jun-04 | 6.350% | 31-Jan-34 | 48.0 | (0.1) | 48.1 | 100.2 | 6.33% | 48.0 | 48.0 | 48.0 | 3.0 | |
| 7 | 20-Aug-04 | 6.590% | 22-Apr-43 | 26.0 | (2.1) | 28.1 | 107.9 | 6.06% | 26.0 | 26.0 | 26.0 | 1.6 | |
| 8 | 24-Aug-04 | 6.350% | 31-Jan-34 | 26.0 | (0.9) | 26.9 | 103.5 | 6.09% | 26.0 | 26.0 | 26.0 | 1.6 | |
| 9 | 19-May-05 | 5.360% | 20-May-36 | 98.1 | 3.7 | 94.4 | 96.2 | 5.62% | 98.1 | 98.1 | 98.1 | 5.5 | |
| 10 | 24-Apr-06 | 5.360% | 20-May-36 | 62.5 | 0.8 | 61.7 | 98.7 | 5.45% | 62.5 | 62.5 | 62.5 | 3.4 | |
| 11 | 19-Oct-06 | 5.000% | 19-Oct-46 | 45.0 | 0.3 | 44.7 | 99.3 | 5.04% | 45.0 | 45.0 | 45.0 | 2.3 | |
| 12 | 13-Mar-07 | 4.890% | 13-Mar-37 | 160.0 | 0.9 | 159.1 | 99.4 | 4.93% | 160.0 | 160.0 | 160.0 | 7.9 | |
| 13 | 3-Mar-09 | 6.030% | 3-Mar-39 | 105.0 | 0.6 | 104.4 | 99.4 | 6.07% | 105.0 | 105.0 | 105.0 | 6.4 | |
| 14 | 16-Jul-09 | 5.490% | 16-Jul-40 | 90.0 | 0.6 | 89.4 | 99.4 | 5.53% | 90.0 | 90.0 | 90.0 | 5.0 | |
| 15 | 15-Mar-10 | 5.490% | 24-Jul-40 | 80.0 | (0.5) | 80.5 | 100.6 | 5.45% | 80.0 | 80.0 | 80.0 | 4.4 | |
| 16 | 15-Mar-10 | 4.400% | 4-Jun-20 | 120.0 | 0.5 | 119.5 | 99.5 | 4.46% | 0.0 | 0.0 | - | 0.0 | |
| 17 | 13-Sep-10 | 5.000% | 19-Oct-46 | 100.0 | (0.2) | 100.2 | 100.2 | 4.98% | 100.0 | 100.0 | 100.0 | 5.0 | |
| 18 | 26-Sep-11 | 4.390% | 26-Sep-41 | 75.0 | 0.5 | 74.5 | 99.3 | 4.43% | 75.0 | 75.0 | 75.0 | 3.3 | |
| 19 | 22-Dec-11 | 4.000% | 22-Dec-51 | 30.0 | 0.2 | 29.8 | 99.5 | 4.03% | 30.0 | 30.0 | 30.0 | 1.2 | |
| 20 | 13-Jan-12 | 3.200% | 13-Jan-22 | 126.0 | 0.7 | 125.3 | 99.5 | 3.26% | 0.0 | 0.0 | - | 0.0 | |
| 21 | 22-May-12 | 3.200% | 13-Jan-22 | 135.0 | (1.3) | 136.3 | 101.0 | 3.08% | 0.0 | 0.0 | - | 0.0 | |
| 22 | 22-May-12 | 4.000% | 22-Dec-51 | 56.3 | 0.3 | 56.0 | 99.5 | 4.02% | 56.3 | 56.3 | 56.3 | 2.3 | |
| 23 | 31-Jul-12 | 3.790% | 31-Jul-62 | 22.5 | 0.1 | 22.4 | 99.5 | 3.81% | 22.5 | 22.5 | 22.5 | 0.9 | |
| 24 | 16-Aug-12 | 3.790% | 31-Jul-62 | 94.0 | 0.8 | 93.2 | 99.2 | 3.83% | 94.0 | 94.0 | 94.0 | 3.6 | |
| 25 | 9-Oct-13 | 4.590% | 9-Oct-43 | 195.8 | 1.1 | 194.6 | 99.4 | 4.63% | 195.8 | 195.8 | 195.8 | 9.1 | |
| 26 | 29-Jan-14 | 4.310% | 29-Jan-64 | 20.0 | 0.1 | 19.9 | 99.4 | 4.34% | 20.0 | 20.0 | 20.0 | 0.9 | |
| 27 | 3-Jun-14 | 4.170% | 3-Jun-44 | 132.0 | 0.8 | 131.2 | 99.4 | 4.21% | 132.0 | 132.0 | 132.0 | 5.6 | |
| 28 | 24-Feb-16 | 3.910% | 24-Feb-46 | 175.0 | 1.1 | 173.9 | 99.4 | 3.95% | 175.0 | 175.0 | 175.0 | 6.9 | |
| 29 | 24-Feb-16 | 2.770% | 24-Feb-26 | 245.0 | 1.1 | 243.9 | 99.6 | 2.82% | 245.0 | 245.0 | 245.0 | 6.9 | |
| 30 | 24-Feb-16 | 1.840% | 24-Feb-21 | 250.0 | 0.9 | 249.1 | 99.6 | 1.92% | 0.0 | 0.0 | - | 0.0 | |
| 31 | 18-Nov-16 | 3.720% | 18-Nov-47 | 180.0 | 0.9 | 179.1 | 99.5 | 3.75% | 180.0 | 180.0 | 180.0 | 6.7 | |
| 32 | 26-Jun-18 | 3.630% | 25-Jun-49 | 281.8 | 1.5 | 280.3 | 99.5 | 3.66% | 281.8 | 281.8 | 281.8 | 10.3 | |
| 33 | 26-Jun-18 | 2.970% | 26-Jun-25 | 131.5 | 0.5 | 131.0 | 99.6 | 3.03% | 131.5 | 131.5 | 131.5 | 4.0 | |
| 34 | 5-Apr-19 | 3.640% | 5-Apr-49 | 102.5 | 0.6 | 101.9 | 99.4 | 3.67% | 102.5 | 102.5 | 102.5 | 3.8 | |
| 35 | 5-Apr-19 | 3.020% | 5-Apr-29 | 225.5 | 1.0 | 224.5 | 99.6 | 3.07% | 225.5 | 225.5 | 225.5 | 6.9 | |
| 36 | 5-Apr-19 | 2.540% | 5-Apr-24 | 287.0 | 1.1 | 285.9 | 99.6 | 2.62% | 287.0 | 287.0 | 287.0 | 7.5 | |
| 37 | 28-Feb-20 | 2.710% | 28-Feb-50 | 57.5 | 0.3 | 57.2 | 99.5 | 2.73% | 57.5 | 57.5 | 57.5 | 1.6 | |
| 38 | 28-Feb-20 | 2.160% | 28-Feb-30 | 76.7 | 0.3 | 76.4 | 99.6 | 2.21% | 76.7 | 76.7 | 76.7 | 1.7 | |
| 39 | 28-Feb-20 | 1.760% | 28-Feb-25 | 76.7 | 0.3 | 76.4 | 99.6 | 1.84% | 76.7 | 76.7 | 76.7 | 1.4 | |
| 40 | 9-Oct-20 | 2.710% | 28-Feb-50 | 76.0 | 0.2 | 75.8 | 99.7 | 2.73% | 76.0 | 76.0 | 76.0 | 2.1 | |
| 41 | 9-Oct-20 | 1.690% | 16-Jan-31 | 152.0 | 0.7 | 151.3 | 99.5 | 1.74% | 152.0 | 152.0 | 152.0 | 2.6 | |
| 42 | 9-Oct-20 | 0.710% | 16-Jan-23 | 76.0 | 0.6 | 75.4 | 99.3 | 1.04% | 76.0 | 0.0 | 5.8 | 0.1 | |
| 43 | 15-Mar-21 | 2.860% | 15-Mar-51 | 42.5 | 1.3 | 41.2 | 96.9 | 3.02% | 42.5 | 42.5 | 42.5 | 1.3 | |
| 44 | 15-Jun-21 | 1.859% | 15-Jun-31 | 42.5 | 1.1 | 41.4 | 97.5 | 2.14% | 42.5 | 42.5 | 42.5 | 0.9 | |
| 45 | 15-Sep-21 | 1.327% | 15-Sep-26 | 42.5 | 1.1 | 41.4 | 97.5 | 1.85% | 42.5 | 42.5 | 42.5 | 0.8 | |
| 46 | 15-Mar-22 | 3.610% | 15-Mar-52 | 136.7 | 0.1 | 136.5 | 99.9 | 3.62% | 136.7 | 136.7 | 136.7 | 4.9 | |
| 47 | 15-Jun-22 | 2.609% | 15-Jun-32 | 136.7 | 0.1 | 136.5 | 99.9 | 2.62% | 136.7 | 136.7 | 136.7 | 3.6 | |
| 48 | 15-Sep-22 | 2.077% | 15-Sep-27 | 136.7 | 0.1 | 136.5 | 99.9 | 2.10% | 136.7 | 136.7 | 136.7 | 2.9 | |
| 49 | 15-Mar-23 | 4.010% | 15-Mar-53 | 194.3 | 1.0 | 193.3 | 99.5 | 4.04% | 0.0 | 194.3 | 149.5 | 6.0 | |
| 50 | 15-Jun-23 | 3.009% | 15-Jun-33 | 194.3 | 1.0 | 193.3 | 99.5 | 3.07% | 0.0 | 194.3 | 104.6 | 3.2 | |
| 51 | 15-Sep-23 | 2.477% | 15-Sep-28 | 194.3 | 1.0 | 193.3 | 99.5 | 2.58% | 0.0 | 194.3 | 59.8 | 1.5 | |
| 52 | | **Subtotal** | | | | | | | 4,636.9 | 5,143.9 | 4,880.7 | 194.0 | |
| 53 | | Treasury OM&A costs | | | | | | | | | | 1.22 | |
| 54 | | Other financing-related fees | | | | | | | | | | 3.40 | |
| 55 | | **Total** | | | | | | | 4,636.9 | 5,143.9 | 4,880.7 | 198.6 | 4.07% |

**Hydro One Networks Inc.**
**Implementation of Decision in EB-2021-0110**

**Distribution Regulatory Taxes**

| *($ millions)* | Supporting Reference | Hydro One Proposed | | | | | OEB Decision Impact | | | | | OEB Approved | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | 2023 | 2024 | 2025 | 2026 | 2027 | 2023 | 2024 | 2025 | 2026 | 2027 | 2023 | 2024 | 2025 | 2026 | 2027 |
| Regulatory Taxes | *See supporting details below* | 36.2 | 53.9 | 40.4 | 57.8 | 67.6 | 3.61 | 5.42 | 7.13 | 6.22 | 4.48 | 39.8 | 59.3 | 47.6 | 64.0 | 72.1 |

***Income Tax Supporting Details***

| | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Rate Base | Exhibit 1.2 | (a) | $ 9,395 | $ 10,031 | $ 10,764 | $ 11,478 | $ 12,105 | $ 65 | $ (52) | $ (192) | $ (325) | $ (449) | $ 9,460 | $ 9,979 | $ 10,573 | $ 11,153 | $ 11,656 |
| Common Equity Capital Structure | | (b) | 40.0% | 40.0% | 40.0% | 40.0% | 40.0% | | | | | | 40.0% | 40.0% | 40.0% | 40.0% | 40.0% |
| Return on Equity | Exhibit 1.4 | (c) | 8.34% | 8.34% | 8.34% | 8.34% | 8.34% | | | | | | 8.34% | 8.34% | 8.34% | 8.34% | 8.34% |
| Return on Equity | | (d) = a x b x c | 313.4 | 334.6 | 359.1 | 382.9 | 403.8 | 2.2 | (1.7) | (6.4) | (10.9) | (15.0) | 315.6 | 332.9 | 352.7 | 372.0 | 388.8 |
| Regulatory Income Tax | | (e) = l | 36.2 | 53.9 | 40.4 | 57.8 | 67.6 | 3.6 | 5.4 | 7.1 | 6.2 | 4.5 | 39.8 | 59.3 | 47.6 | 64.0 | 72.1 |
| Regulatory Net Income (before tax) | | (f) = d + e | 349.6 | 388.5 | 399.5 | 440.7 | 471.4 | 5.8 | 3.7 | 0.7 | (4.6) | (10.5) | 355.4 | 392.2 | 400.3 | 436.0 | 460.9 |
| Timing Differences *(Note 1)* | | (g) | (211.4) | (183.6) | (245.3) | (221.0) | (214.7) | 7.8 | 16.8 | 26.2 | 28.1 | 27.4 | (203.6) | (166.8) | (219.1) | (193.0) | (187.3) |
| Taxable Income | | (h) = f + g | 138.2 | 205.0 | 154.2 | 219.6 | 256.7 | 13.6 | 20.4 | 26.9 | 23.5 | 16.9 | 151.8 | 225.4 | 181.1 | 243.1 | 273.6 |
| Tax Rate | | (i) | 26.5% | 26.5% | 26.5% | 26.5% | 26.5% | | | | | | 26.5% | 26.5% | 26.5% | 26.5% | 26.5% |
| Income Tax | | (j) = h x i | 36.6 | 54.3 | 40.9 | 58.2 | 68.0 | | | | | | 40.2 | 59.7 | 48.0 | 64.4 | 72.5 |
| less: Income Tax Credits | | (k) | (0.4) | (0.4) | (0.4) | (0.4) | (0.4) | | | | | | (0.4) | (0.4) | (0.4) | (0.4) | (0.4) |
| Regulatory Income Tax | | (l) = j + k | 36.2 | 53.9 | 40.4 | 57.8 | 67.6 | | | | | | 39.8 | 59.3 | 47.6 | 64.0 | 72.1 |
| Income Taxes | | | 36.2 | 53.9 | 40.4 | 57.8 | 67.6 | 3.6 | 5.4 | 7.1 | 6.2 | 4.5 | 39.8 | 59.3 | 47.6 | 64.0 | 72.1 |
| Note 1. Book to Tax Timing Differences | | | | | | | | | | | | | | | | | |
| Depreciation | | | 465.1 | 488.2 | 531.7 | 569.4 | 606.9 | (3.7) | (6.9) | (17.0) | (23.5) | (28.4) | 461.4 | 481.3 | 514.7 | 545.9 | 578.6 |
| CCA | Exhibit O-01-02 Attachment 9 (page 10 Dx) | | (576.1) | (569.8) | (676.9) | (691.2) | (720.6) | 11.5 | 23.6 | 43.0 | 51.1 | 55.4 | (564.6) | (546.1) | (633.9) | (640.1) | (665.1) |
| Other Timing Differences | | | (100.4) | (102.0) | (100.1) | (99.3) | (101.1) | 0.0 | 0.1 | 0.1 | 0.5 | 0.3 | (100.4) | (102.0) | (99.9) | (98.8) | (100.7) |
| Total Timing Differences | | | (211.4) | (183.6) | (245.3) | (221.0) | (214.7) | 7.8 | 16.8 | 26.2 | 28.1 | 27.4 | (203.6) | (166.8) | (219.1) | (193.0) | (187.3) |

**HYDRO ONE NETWORKS INC.**
**DISTRIBUTION**
**Calculation of Utility Income Taxes**
**Test Years (2023 to 2027)**
**Year Ending December 31**
($ Millions)

| Line No. | Particulars | | 2023 | 2024 | 2025 | 2026 | 2027 |
|---|---|---|---|---|---|---|---|
| | Determination of Taxable Income | | | | | | |
| 1 | Regulatory Net Income (before tax) | $ | 355.4 | 392.2 | 400.2 | 436.0 | 460.8 |
| 2 | Book to Tax Adjustments: | | | | | | |
| 3 | Other Post Employment Benefits expense | | 44.7 | 45.7 | 47.4 | 49.4 | 50.5 |
| 4 | Other Post Employment Benefits payments | | (34.5) | (35.5) | (36.6) | (37.5) | (38.5) |
| 5 | Depreciation and amortization | | 461.4 | 481.3 | 514.7 | 545.9 | 578.6 |
| 7 | Capital Cost Allowance | | (564.6) | (546.1) | (633.9) | (640.2) | (665.4) |
| 8 | Removal costs | | (4.0) | (4.0) | (4.0) | (4.0) | (4.0) |
| 9 | Environmental costs | | (5.5) | (5.4) | (1.0) | - | - |
| 10 | Hedge loss - amortization | | - | - | - | - | - |
| 11 | Non-deductible meals & entertainment | | 2.1 | 2.1 | 2.1 | 2.1 | 2.1 |
| 12 | Capital amounts expensed under $2K | | - | - | - | - | - |
| 13 | Research & Development ITC | | - | - | - | - | - |
| 14 | Ontario education credits | | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 |
| 15 | Capitalized overhead costs | | (63.3) | (63.8) | (66.9) | (65.9) | (66.8) |
| 16 | Capitalized pension costs | | (40.9) | (42.2) | (42.4) | (43.9) | (44.8) |
| 17 | Debt Issuance costs - amortization | | 1.7 | 1.8 | 1.9 | 2.1 | 2.2 |
| 18 | Debt Issuance costs - 21e deduction | | (2.4) | (2.3) | (2.3) | (2.5) | (2.6) |
| 19 | Premium/Discount - amortization | | (0.3) | (0.4) | (0.4) | (0.4) | (0.5) |
| 20 | Bond discount deduction | | - | - | - | - | - |
| 21 | Non-deductible LTIP | | - | - | - | - | - |
| 22 | Capital Contribution True-Up Adjustment | | - | - | - | - | - |
| 23 | Other | | 1.6 | 1.6 | 1.5 | 1.4 | 1.4 |
| | | $ | (203.6) | (166.8) | (219.1) | (193.0) | (187.3) |
| 23 | Regulatory Taxable Income | $ | 151.8 | 225.4 | 181.1 | 243.0 | 273.5 |
| 24 | Corporate Income Tax Rate | % | 26.5 | 26.5 | 26.5 | 26.5 | 26.5 |
| 25 | Subtotal | $ | 40.2 | 59.7 | 48.0 | 64.4 | 72.5 |
| 26 | Less: R&D ITC / Ontario education credits | | (0.4) | (0.4) | (0.4) | (0.4) | (0.4) |
| 27 | Regulatory Income Tax | $ | 39.8 | 59.3 | 47.6 | 64.0 | 72.1 |

**HYDRO ONE NETWORKS INC.**
**DISTRIBUTION**
**Calculation of Utility Income Taxes**
**Test Years (2023 to 2027)**
**Year Ending December 31**
($ Millions)

| 2023 CCA Calculation | CCA Class | Opening UCC | Net Additions | UCC pre-1/2 yr | 50% Net Additions | Bonus Depreciation | UCC for CCA | CCA Rate | CCA | Closing UCC |
|---|---|---|---|---|---|---|---|---|---|---|
| | 1 | 1,275.3 | 23.0 | 1,298.3 | 11.5 | 23.0 | 1,309.9 | 4% | 52.4 | 1,246.0 |
| | 1b | 0.0 | - | 0.0 | - | - | 0.0 | 6% | 0.0 | 0.0 |
| | 2 | 156.7 | - | 156.7 | - | - | 156.7 | 6% | 9.4 | 147.3 |
| | 3 | 9.2 | - | 9.2 | - | - | 9.2 | 5% | 0.5 | 8.7 |
| | 6 | 14.2 | - | 14.2 | - | - | 14.2 | 10% | 1.4 | 12.8 |
| | 7 | 1.3 | - | 1.3 | - | - | 1.3 | 15% | 0.2 | 1.1 |
| | 8 | 110.5 | 55.5 | 165.9 | 27.7 | 55.5 | 193.7 | 20% | 38.7 | 127.2 |
| | 9 | 1.0 | - | 1.0 | - | - | 1.0 | 25% | 0.3 | 0.8 |
| | 10 | 45.9 | 31.8 | 77.7 | 15.9 | 31.8 | 93.7 | 30% | 28.1 | 49.6 |
| | 12 | - | 43.3 | 43.3 | 21.6 | 21.6 | 43.3 | 100% | 43.3 | - |
| | 13 | 19.8 | 5.0 | 24.8 | 2.5 | - | 22.3 | N/A | 3.2 | 21.6 |
| | 14 | 1.2 | - | 1.2 | - | - | 1.2 | N/A | 0.1 | 1.1 |
| 14.1 (Pre-2017; formerly ECE) | 14.1 | 0.5 | - | 0.5 | - | - | 0.5 | 7% | 0.0 | 0.4 |
| 14.1 (Post-2017) | 14.1 | 7.2 | 4.5 | 11.7 | 2.2 | 4.5 | 13.9 | 5% | 0.7 | 11.0 |
| | 17 | 27.1 | - | 27.1 | - | - | 27.1 | 8% | 2.2 | 24.9 |
| | 35 | - | - | - | - | - | - | 7% | - | - |
| | 42 | 0.1 | - | 0.1 | - | - | 0.1 | 12% | 0.0 | 0.1 |
| | 45 | 0.0 | - | 0.0 | - | - | 0.0 | 45% | 0.0 | 0.0 |
| | 46 | 3.4 | - | 3.4 | - | - | 3.4 | 30% | 1.0 | 2.4 |
| | 47 | 3,843.5 | 649.4 | 4,492.9 | 324.7 | 649.4 | 4,817.6 | 8% | 385.4 | 4,107.5 |
| | 50 | 1.3 | 1.8 | 3.1 | 0.9 | 1.8 | 4.0 | 55% | 2.2 | 0.9 |
| | 52 | - | - | - | - | - | - | 100% | - | - |
| | ECE | 14.9 | - | 14.9 | - | - | 14.9 | 7% | 1.0 | 13.8 |
| | | 5,533.0 | 814.2 | 6,347.2 | 407.1 | 787.6 | 6,727.7 | | 570.1 | 5,777.1 |
| | | | | | | | | | (5.5) | Non-Regulatory |
| | | | | | | | | | 564.6 | Total CCA for RR |

**HYDRO ONE NETWORKS INC.**
**DISTRIBUTION**
**Calculation of Utility Income Taxes**
**Test Years (2023 to 2027)**
**Year Ending December 31**
($ Millions)

| **2024 CCA Calculation** | CCA Class | Opening UCC | Net Additions | UCC pre-1/2 yr | 50% Net Additions | Bonus Depreciation | UCC for CCA | CCA Rate | CCA | Closing UCC |
|---|---|---|---|---|---|---|---|---|---|---|
| | 1 | 1,246.0 | 53.8 | 1,299.8 | 26.9 | 26.9 | 1,299.8 | 0.0 | 52.0 | 1,247.8 |
| | 1b | 0.0 | - | 0.0 | - | - | 0.0 | 0.1 | 0.0 | 0.0 |
| | 2 | 147.3 | - | 147.3 | - | - | 147.3 | 0.1 | 8.8 | 138.5 |
| | 3 | 8.7 | - | 8.7 | - | - | 8.7 | 0.1 | 0.4 | 8.3 |
| | 6 | 12.8 | - | 12.8 | - | - | 12.8 | 0.1 | 1.3 | 11.5 |
| | 7 | 1.1 | - | 1.1 | - | - | 1.1 | 0.2 | 0.2 | 0.9 |
| | 8 | 127.2 | 77.8 | 205.0 | 38.9 | 38.9 | 205.0 | 0.2 | 41.0 | 164.0 |
| | 9 | 0.8 | - | 0.8 | - | - | 0.8 | 0.3 | 0.2 | 0.6 |
| | 10 | 49.6 | 32.6 | 82.3 | 16.3 | 16.3 | 82.3 | 0.3 | 24.7 | 57.6 |
| | 12 | - | 33.5 | 33.5 | 16.7 | 16.7 | 33.5 | 1.0 | 33.5 | - |
| | 13 | 21.6 | 13.8 | 35.4 | 6.9 | - | 28.5 | N/A | 4.6 | 30.8 |
| | 14 | 1.1 | - | 1.1 | - | - | 1.1 | N/A | 0.1 | 1.0 |
| 14.1 (Pre-2017; formerly ECE) | 14.1 | 0.4 | - | 0.4 | - | - | 0.4 | 0.1 | 0.0 | 0.4 |
| 14.1 (Post-2017) | 14.1 | 11.0 | 8.0 | 19.0 | 4.0 | 4.0 | 19.0 | 0.1 | 0.9 | 18.0 |
| | 17 | 24.9 | - | 24.9 | - | - | 24.9 | 0.1 | 2.0 | 22.9 |
| | 35 | - | - | - | - | - | - | 0.1 | - | - |
| | 42 | 0.1 | - | 0.1 | - | - | 0.1 | 0.1 | 0.0 | 0.1 |
| | 45 | 0.0 | - | 0.0 | - | - | 0.0 | 0.5 | 0.0 | 0.0 |
| | 46 | 2.4 | - | 2.4 | - | - | 2.4 | 0.3 | 0.7 | 1.7 |
| | 47 | 4,107.5 | 626.8 | 4,734.2 | 313.4 | 313.4 | 4,734.2 | 0.1 | 378.7 | 4,355.5 |
| | 50 | 0.9 | 1.3 | 2.2 | 0.7 | 0.7 | 2.2 | 0.6 | 1.2 | 1.0 |
| | 52 | - | - | - | - | - | - | 1.0 | - | - |
| | ECE | 13.8 | - | 13.8 | - | - | 13.8 | 0.1 | 1.0 | 12.9 |
| | | 5,777.1 | 847.6 | 6,624.7 | 423.8 | 416.9 | 6,617.8 | | 551.3 | 6,073.4 |
| | | | | | | | | | (5.2) | Non-Regulatory |
| | | | | | | | | | 546.1 | Total CCA for RR |

**HYDRO ONE NETWORKS INC.**
**DISTRIBUTION**
**Calculation of Utility Income Taxes**
**Test Years (2023 to 2027)**
**Year Ending December 31**
($ Millions)

| **2025 CCA Calculation** | CCA Class | Opening UCC | Net Additions | UCC pre-1/2 yr | 50% Net Additions | Bonus Depreciation | UCC for CCA | CCA Rate | CCA | Closing UCC |
|---|---|---|---|---|---|---|---|---|---|---|
| | 1 | 1,247.8 | 36.7 | 1,284.5 | 18.3 | 18.3 | 1,284.5 | 0.0 | 51.4 | 1,233.1 |
| | 1b | 0.0 | - | 0.0 | - | - | 0.0 | 0.1 | 0.0 | 0.0 |
| | 2 | 138.5 | - | 138.5 | - | - | 138.5 | 0.1 | 8.3 | 130.2 |
| | 3 | 8.3 | - | 8.3 | - | - | 8.3 | 0.1 | 0.4 | 7.9 |
| | 6 | 11.5 | - | 11.5 | - | - | 11.5 | 0.1 | 1.1 | 10.3 |
| | 7 | 0.9 | - | 0.9 | - | - | 0.9 | 0.2 | 0.1 | 0.8 |
| | 8 | 164.0 | 96.3 | 260.3 | 48.2 | 48.2 | 260.3 | 0.2 | 52.1 | 208.3 |
| | 9 | 0.6 | - | 0.6 | - | - | 0.6 | 0.3 | 0.1 | 0.4 |
| | 10 | 57.6 | 33.6 | 91.1 | 16.8 | 16.8 | 91.1 | 0.3 | 27.3 | 63.8 |
| | 12 | - | 76.4 | 76.4 | 38.2 | 38.2 | 76.4 | 1.0 | 76.4 | - |
| | 13 | 30.8 | 9.5 | 40.3 | 4.8 | - | 35.6 | N/A | 5.8 | 34.6 |
| | 14 | 1.0 | - | 1.0 | - | - | 1.0 | N/A | 0.1 | 0.8 |
| 14.1 (Pre-2017; formerly ECE) | 14.1 | 0.4 | - | 0.4 | - | - | 0.4 | 0.1 | 0.0 | 0.4 |
| 14.1 (Post-2017) | 14.1 | 18.0 | 6.6 | 24.7 | 3.3 | 3.3 | 24.7 | 0.1 | 1.2 | 23.4 |
| | 17 | 22.9 | - | 22.9 | - | - | 22.9 | 0.1 | 1.8 | 21.1 |
| | 35 | - | - | - | - | - | - | 0.1 | - | - |
| | 42 | 0.1 | - | 0.1 | - | - | 0.1 | 0.1 | 0.0 | 0.1 |
| | 45 | 0.0 | - | 0.0 | - | - | 0.0 | 0.5 | 0.0 | 0.0 |
| | 46 | 1.7 | - | 1.7 | - | - | 1.7 | 0.3 | 0.5 | 1.2 |
| | 47 | 4,355.5 | 751.4 | 5,106.9 | 375.7 | 375.7 | 5,106.9 | 0.1 | 408.5 | 4,698.3 |
| | 50 | 1.0 | 3.7 | 4.7 | 1.8 | 1.8 | 4.7 | 0.6 | 2.6 | 2.1 |
| | 52 | - | - | - | - | - | - | 1.0 | - | - |
| | ECE | 12.9 | - | 12.9 | - | - | 12.9 | 0.1 | 0.9 | 12.0 |
| | | 6,073.4 | 1,014.1 | 7,087.5 | 507.1 | 502.3 | 7,082.7 | | 638.8 | 6,448.7 |
| | | | | | | | | | (5.0) | Non-Regulatory |
| | | | | | | | | | 633.9 | Total CCA for RR |

# HYDRO ONE NETWORKS INC.
## DISTRIBUTION
### Calculation of Utility Income Taxes
### Test Years (2023 to 2027)
### Year Ending December 31
($ Millions)

| 2026 CCA Calculation | CCA Class | Opening UCC | Net Additions | UCC pre-1/2 yr | 50% Net Additions | Bonus Depreciation | UCC for CCA | CCA Rate | CCA | Closing UCC |
|---|---|---|---|---|---|---|---|---|---|---|
| | 1 | 1,233.1 | 24.5 | 1,257.6 | 12.3 | 12.3 | 1,257.6 | 0.0 | 50.3 | 1,207.3 |
| | 1b | 0.0 | - | 0.0 | - | - | 0.0 | 0.1 | 0.0 | 0.0 |
| | 2 | 130.2 | - | 130.2 | - | - | 130.2 | 0.1 | 7.8 | 122.4 |
| | 3 | 7.9 | - | 7.9 | - | - | 7.9 | 0.1 | 0.4 | 7.5 |
| | 6 | 10.3 | - | 10.3 | - | - | 10.3 | 0.1 | 1.0 | 9.3 |
| | 7 | 0.8 | - | 0.8 | - | - | 0.8 | 0.2 | 0.1 | 0.7 |
| | 8 | 208.3 | 86.5 | 294.8 | 43.2 | 43.2 | 294.8 | 0.2 | 59.0 | 235.8 |
| | 9 | 0.4 | - | 0.4 | - | - | 0.4 | 0.3 | 0.1 | 0.3 |
| | 10 | 63.8 | 33.6 | 97.4 | 16.8 | 16.8 | 97.4 | 0.3 | 29.2 | 68.2 |
| | 12 | - | 55.6 | 55.6 | 27.8 | 27.8 | 55.6 | 1.0 | 55.6 | - |
| | 13 | 34.6 | 5.1 | 39.7 | 2.6 | - | 37.1 | N/A | 4.6 | 35.0 |
| | 14 | 0.8 | - | 0.8 | - | - | 0.8 | N/A | 0.1 | 0.7 |
| 14.1 (Pre-2017; formerly ECE) | 14.1 | 0.4 | - | 0.4 | - | - | 0.4 | 0.1 | 0.0 | 0.3 |
| 14.1 (Post-2017) | 14.1 | 23.4 | 4.5 | 27.9 | 2.2 | 2.2 | 27.9 | 0.1 | 1.4 | 26.5 |
| | 17 | 21.1 | - | 21.1 | - | - | 21.1 | 0.1 | 1.7 | 19.4 |
| | 35 | - | - | - | - | - | - | 0.1 | - | - |
| | 42 | 0.1 | - | 0.1 | - | - | 0.1 | 0.1 | 0.0 | 0.1 |
| | 45 | 0.0 | - | 0.0 | - | - | 0.0 | 0.5 | 0.0 | 0.0 |
| | 46 | 1.2 | - | 1.2 | - | - | 1.2 | 0.3 | 0.4 | 0.8 |
| | 47 | 4,698.3 | 671.7 | 5,370.0 | 335.9 | 335.9 | 5,370.0 | 0.1 | 429.6 | 4,940.4 |
| | 50 | 2.1 | 2.7 | 4.8 | 1.3 | 1.3 | 4.8 | 0.6 | 2.6 | 2.1 |
| | 52 | - | - | - | - | - | - | 1.0 | - | - |
| | ECE | 12.0 | - | 12.0 | - | - | 12.0 | 0.1 | 0.8 | 11.1 |
| | | 6,448.7 | 884.1 | 7,332.8 | 442.1 | 439.5 | 7,330.3 | | 644.8 | 6,688.0 |
| | | | | | | | | | (4.7) | Non-Regulatory |
| | | | | | | | | | 640.2 | Total CCA for RR |

**HYDRO ONE NETWORKS INC.**
**DISTRIBUTION**
**Calculation of Utility Income Taxes**
**Test Years (2023 to 2027)**
**Year Ending December 31**
($ Millions)

| **2027 CCA Calculation** | CCA Class | Opening UCC | Net Additions | UCC pre-1/2 yr | 50% Net Additions | Bonus Depreciation | UCC for CCA | CCA Rate | CCA | Closing UCC |
|---|---|---|---|---|---|---|---|---|---|---|
| | 1 | 1,207.3 | 41.8 | 1,249.1 | 20.9 | 20.9 | 1,249.1 | 0.0 | 50.0 | 1,199.2 |
| | 1b | 0.0 | - | 0.0 | - | - | 0.0 | 0.1 | 0.0 | 0.0 |
| | 2 | 122.4 | - | 122.4 | - | - | 122.4 | 0.1 | 7.3 | 115.0 |
| | 3 | 7.5 | - | 7.5 | - | - | 7.5 | 0.1 | 0.4 | 7.1 |
| | 6 | 9.3 | - | 9.3 | - | - | 9.3 | 0.1 | 0.9 | 8.4 |
| | 7 | 0.7 | - | 0.7 | - | - | 0.7 | 0.2 | 0.1 | 0.6 |
| | 8 | 235.8 | 82.9 | 318.7 | 41.5 | 41.5 | 318.7 | 0.2 | 63.7 | 255.0 |
| | 9 | 0.3 | - | 0.3 | - | - | 0.3 | 0.3 | 0.1 | 0.2 |
| | 10 | 68.2 | 34.9 | 103.1 | 17.5 | 17.5 | 103.1 | 0.3 | 30.9 | 72.2 |
| | 12 | - | 53.4 | 53.4 | 26.7 | 26.7 | 53.4 | 1.0 | 53.4 | - |
| | 13 | 35.0 | 10.5 | 45.5 | 5.2 | - | 40.3 | N/A | 5.6 | 39.9 |
| | 14 | 0.7 | - | 0.7 | - | - | 0.7 | N/A | 0.1 | 0.6 |
| 14.1 (Pre-2017; formerly ECE) | 14.1 | 0.3 | - | 0.3 | - | - | 0.3 | 0.1 | 0.0 | 0.3 |
| 14.1 (Post-2017) | 14.1 | 26.5 | 6.9 | 33.4 | 3.4 | 3.4 | 33.4 | 0.1 | 1.7 | 31.7 |
| | 17 | 19.4 | - | 19.4 | - | - | 19.4 | 0.1 | 1.6 | 17.9 |
| | 35 | - | - | - | - | - | - | 0.1 | - | - |
| | 42 | 0.1 | - | 0.1 | - | - | 0.1 | 0.1 | 0.0 | 0.1 |
| | 45 | 0.0 | - | 0.0 | - | - | 0.0 | 0.5 | 0.0 | 0.0 |
| | 46 | 0.8 | - | 0.8 | - | - | 0.8 | 0.3 | 0.2 | 0.6 |
| | 47 | 4,940.4 | 690.4 | 5,630.8 | 345.2 | 345.2 | 5,630.8 | 0.1 | 450.5 | 5,180.3 |
| | 50 | 2.1 | 2.6 | 4.8 | 1.3 | 1.3 | 4.8 | 0.6 | 2.6 | 2.2 |
| | 52 | - | - | - | - | - | - | 1.0 | - | - |
| | ECE | 11.1 | - | 11.1 | - | - | 11.1 | 0.1 | 0.6 | 10.6 |
| | | 6,688.0 | 923.5 | 7,611.5 | 461.7 | 456.5 | 7,606.2 | | 669.8 | 6,941.7 |
| | | | | | | | | | (4.4) | Non-Regulatory |
| | | | | | | | | | 665.4 | Total CCA for RR |

**Hydro One Networks Inc.**
**Implementation of Decision in EB-2021-0110**

**Distribution External Revenue**

| *($ millions)* | Supporting Reference | Hydro One Proposed | | | | | OEB Decision Impact | | | | | OEB Approved | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | 2023 | 2024 | 2025 | 2026 | 2027 | 2023 | 2024 | 2025 | 2026 | 2027 | 2023 | 2024 | 2025 | 2026 | 2027 |
| External Revenue | Exhibit D-02-02, Attachment 1 | (46.4) | (46.5) | (46.5) | (46.0) | (46.1) | 2.8 | 2.6 | 2.4 | 2.2 | 1.9 | (43.6) | (43.9) | (44.1) | (43.8) | (44.2) |

OEB Decision Impact Supporting Details

| **Adjustments** | **Settlement Proposal Reference** | 2023 | 2024 | 2025 | 2026 | 2027 |
|---|---|---|---|---|---|---|
| External Revenue | Part C, Issue 39 | 2.8 | 2.7 | 2.4 | 2.1 | 1.9 |

**Hydro One Networks Inc.**
**Implementation of Decision in EB-2021-0110**

**Distribution Working Capital Adjustment**

| | Hydro One Proposed | | | | | OEB Decision Impact | | | | | OEB Approved | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | **2023** | **2024** | **2025** | **2026** | **2027** | **2023** | **2024** | **2025** | **2026** | **2027** | **2023** | **2024** | **2025** | **2026** | **2027** |
| **Adjusted Working Capital in Rate Base** | **251.7** | **254.8** | **257.4** | **260.7** | **263.8** | **(2.0)** | **(1.6)** | **(1.6)** | **(1.5)** | **(1.6)** | **249.8** | **253.2** | **255.8** | **259.2** | **262.2** |
| Long-term debt | 4.07% | 4.07% | 4.07% | 4.07% | 4.07% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 4.07% | 4.07% | 4.07% | 4.07% | 4.07% |
| Short-term debt | 1.56% | 1.56% | 1.56% | 1.56% | 1.56% | | | | | | 1.56% | 1.56% | 1.56% | 1.56% | 1.56% |
| Common equity | 8.34% | 8.34% | 8.34% | 8.34% | 8.34% | | | | | | 8.34% | 8.34% | 8.34% | 8.34% | 8.34% |
| Return on Long-term debt | 5.7 | 5.8 | 5.9 | 5.9 | 6.0 | (0.0) | (0.0) | (0.0) | (0.0) | (0.0) | 5.7 | 5.8 | 5.8 | 5.9 | 6.0 |
| Return on Short-term debt | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | (0.0) | (0.0) | (0.0) | (0.0) | (0.0) | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 |
| Return on Common equity | 8.4 | 8.5 | 8.6 | 8.7 | 8.8 | (0.1) | (0.1) | (0.1) | (0.1) | (0.1) | 8.3 | 8.4 | 8.5 | 8.6 | 8.7 |
| **Total Return on Capital** | **14.3** | **14.5** | **14.6** | **14.8** | **15.0** | **(0.1)** | **(0.1)** | **(0.1)** | **(0.1)** | **(0.1)** | **14.2** | **14.4** | **14.5** | **14.7** | **14.9** |
| Income tax | 3.0 | 3.1 | 3.1 | 3.1 | 3.2 | (0.0) | (0.0) | (0.0) | (0.0) | (0.0) | 3.0 | 3.0 | 3.1 | 3.1 | 3.2 |
| **Total Revenue Requirement Associated with Working Capital in Rate Base** | **17.3** | **17.5** | **17.7** | **17.9** | **18.2** | **(0.1)** | **(0.1)** | **(0.1)** | **(0.1)** | **(0.1)** | **17.2** | **17.4** | **17.6** | **17.8** | **18.0** |
| Revenue Requirement Associated with Working Capital in rate base | 17.3 | 17.5 | 17.7 | 17.9 | 18.2 | (0.1) | (0.1) | (0.1) | (0.1) | (0.1) | 17.2 | 17.4 | 17.6 | 17.8 | 18.0 |
| Less Productivity Factor applied to Working Capital | - | (0.1) | (0.2) | (0.2) | (0.3) | | (0.0) | (0.1) | (0.1) | (0.2) | - | (0.1) | (0.2) | (0.3) | (0.5) |
| **Revenue Requirement calculation (prior methodology)** | **17.3** | **17.5** | **17.6** | **17.7** | **17.9** | **(0.1)** | **(0.1)** | **(0.2)** | **(0.2)** | **(0.3)** | **17.2** | **17.3** | **17.4** | **17.5** | **17.6** |
| Revenue Requirement calculation (OEB Decision) [1] | **17.3** | **17.6** | **18.0** | **18.3** | **18.7** | **(0.1)** | **(0.2)** | **(0.2)** | **(0.2)** | **(0.3)** | **17.2** | **17.5** | **17.8** | **18.1** | **18.4** |
| Difference between the two methodologies | - | 0.2 | 0.4 | 0.6 | 0.8 | | (0.0) | (0.0) | (0.0) | 0.0 | - | 0.2 | 0.4 | 0.6 | 0.8 |

Note [1]: The calculation for revenue requirement associated with working capital based on the OEB decision would exclude recovering incremental revenue associated with working capital as part of the capital factor

**Hydro One Networks Inc.**
**Implementation of Decision in EB-2021-0110**

**Distribution Deferral and Variance Accounts**

| ($ millions) | Supporting Reference | Hydro One Proposed Total | Hydro One Proposed 2023 | Hydro One Proposed 2024 | Hydro One Proposed 2025 | Hydro One Proposed 2026 | Hydro One Proposed 2027 | OEB Decision Impact 2023 | OEB Decision Impact 2024 | OEB Decision Impact 2025 | OEB Decision Impact 2026 | OEB Decision Impact 2027 | Total | OEB Approved 2023 | OEB Approved 2024 | OEB Approved 2025 | OEB Approved 2026 | OEB Approved 2027 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Deferral and Variance Accounts Disposition | See supporting details below | (87.7) | (17.5) | (17.5) | (17.5) | (17.5) | (17.5) | (11.5) | (11.5) | (11.5) | 17.5 | 17.5 | (87.2) | (29.1) | (29.1) | (29.1) | | |
| **Deferral and Variance Accounts Details** | | | | | | | | | | | | | | | | | | |
| LV Variance Account | | 2.08 | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 | | | | | | 2.08 | 0.7 | 0.7 | 0.7 | | |
| RSVA - Wholesale Market Service Charge | | (21.75) | (4.3) | (4.3) | (4.3) | (4.3) | (4.3) | | | | | | (21.7) | (7.2) | (7.2) | (7.2) | | |
| Variance WMS – Sub-account CBR Class B | | (2.98) | (0.6) | (0.6) | (0.6) | (0.6) | (0.6) | | | | | | (3.0) | (1.0) | (1.0) | (1.0) | | |
| RSVA - Retail Transmission Network Charge | | (15.02) | (3.0) | (3.0) | (3.0) | (3.0) | (3.0) | | | | | | (15.02) | (5.0) | (5.0) | (5.0) | | |
| RSVA - Retail Transmission Connection Charge | | (14.83) | (3.0) | (3.0) | (3.0) | (3.0) | (3.0) | | | | | | (14.83) | (4.9) | (4.9) | (4.9) | | |
| RSVA - Power (excluding Global Adjustment) | | (3.00) | (0.6) | (0.6) | (0.6) | (0.6) | (0.6) | | | | | | (3.00) | (1.0) | (1.0) | (1.0) | | |
| RSVA - Global Adjustment | | (13.81) | (2.8) | (2.8) | (2.8) | (2.8) | (2.8) | | | | | | (13.81) | (4.6) | (4.6) | (4.6) | | |
| Smart Metering Entity Charge Variance Account | | (0.15) | (0.0) | (0.0) | (0.0) | (0.0) | (0.0) | | | | | | (0.15) | (0.1) | (0.1) | (0.1) | | |
| Disposition and Recovery/Refund of Regulatory Balances (2018) - Norfolk | | (0.05) | (0.0) | (0.0) | (0.0) | (0.0) | (0.0) | | | | | | (0.05) | (0.0) | (0.0) | (0.0) | | |
| Disposition and Recovery/Refund of Regulatory Balances (2018) - Woodstock | | (0.03) | (0.0) | (0.0) | (0.0) | (0.0) | (0.0) | | | | | | (0.03) | (0.0) | (0.0) | (0.0) | | |
| **Group 1 Sub-Total (including Account 1589 - Global Adjustment)** | | (69.5) | (13.9) | (13.9) | (13.9) | (13.9) | (13.9) | | | | | | (69.5) | (23.2) | (23.2) | (23.2) | - | - |
| Other Regulatory Assets - Sub-Account - OEB Cost Differential Account | | (2.5) | (0.5) | (0.5) | (0.5) | (0.5) | (0.5) | | | | | | (2.5) | (0.8) | (0.8) | (0.8) | | |
| Other Regulatory Assets - Sub-Account - Long Term Load Transfer (LTLT) Rate Impact Mitigation Deferral Account | | 0.8 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | | | | | | 0.8 | 0.3 | 0.3 | 0.3 | | |
| Other Regulatory Assets - Sub-Account - Bill Impact Mitigation Variance Account | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | | | | | | 0.0 | 0.0 | 0.0 | 0.0 | | |
| Other Regulatory Assets - Sub-Account - Customer Choice Initiative | | 0.9 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | | | | | | 0.9 | 0.3 | 0.3 | 0.3 | | |
| Other Regulatory Assets - Sub-Account - OPEB Cost Deferral Account | | 69.1 | 13.8 | 13.8 | 13.8 | 13.8 | 13.8 | | | | | | 69.1 | 23.0 | 23.0 | 23.0 | | |
| Other Regulatory Assets - Sub-Account - Smart Grid Fund (SGF) Pilot Deferral Account | | 2.3 | 0.5 | 0.5 | 0.5 | 0.5 | 0.5 | | | | | | 2.3 | 0.8 | 0.8 | 0.8 | | |
| Retail Cost Variance Account - Retail and STR6 | | 0.8 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | | | | | | 0.8 | 0.3 | 0.3 | 0.3 | | |
| OPEB Asymmetrical Carrying Charge Variance Account | | (1.5) | (0.3) | (0.3) | (0.3) | (0.3) | (0.3) | | | | | | (1.5) | (0.5) | (0.5) | (0.5) | | |
| Pension Cost Differential Variance Account | | (23.9) | (4.8) | (4.8) | (4.8) | (4.8) | (4.8) | | | | | | (23.9) | (8.0) | (8.0) | (8.0) | | |
| Earnings Sharing Mechanism (ESM) Deferral Account | | (15.2) | (3.0) | (3.0) | (3.0) | (3.0) | (3.0) | | | | | | (15.2) | (5.1) | (5.1) | (5.1) | | |
| PILs and Tax Variance for 2006 and Subsequent Years- Sub-account CCA Changes | | (48.9) | (9.8) | (9.8) | (9.8) | (9.8) | (9.8) | | | | | | (47.1) | (15.7) | (15.7) | (15.7) | | |
| PILs and Tax Variance for 2006 and Subsequent Years- Sub-account CCA Changes - Norfolk | | | | | | | | | | | | | (0.4) | (0.1) | (0.1) | (0.1) | | |
| PILs and Tax Variance for 2006 and Subsequent Years- Sub-account CCA Changes - Haldimand | | | | | | | | | | | | | (0.5) | (0.2) | (0.2) | (0.2) | | |
| PILs and Tax Variance for 2006 and Subsequent Years- Sub-account CCA Changes - Woodstock | | | | | | | | | | | | | (0.3) | (0.1) | (0.1) | (0.1) | | |
| **Total Group 2 Accounts (including 1592)** | | (18.1) | (3.6) | (3.6) | (3.6) | (3.6) | (3.6) | | | | | | (17.6) | (5.9) | (5.9) | (5.9) | - | - |
| **Total Regulatory Accounts Seeking Disposition – Group 1 & 2** | | **(87.7)** | **(17.5)** | **(17.5)** | **(17.5)** | **(17.5)** | **(17.5)** | | | | | | **(87.2)** | **(29.1)** | **(29.1)** | **(29.1)** | - | - |

**Hydro One Networks Inc.**
**Implementation of Decision in EB-2021-0110**

**Distribution In-Service Additions**

| ($ millions) | Supporting Reference | Hydro One Proposed | | | | | OEB Decision Impact | | | | | OEB Approved | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | 2023 | 2024 | 2025 | 2026 | 2027 | 2023 | 2024 | 2025 | 2026 | 2027 | 2023 | 2024 | 2025 | 2026 | 2027 |
| In-Service Additions | Exhibit O-02-01, Attachment 9<br>Supporting details below | 1,012.5 | 1,080.9 | 1,266.6 | 1,116.9 | 1,165.9 | (102.5) | (133.5) | (153.5) | (132.3) | (143.3) | 910.0 | 947.4 | 1,113.1 | 984.6 | 1,022.6 |

OEB Decision Impact Supporting Details

| Adjustments | Settlement Proposal Reference | 2023 | 2024 | 2025 | 2026 | 2027 |
|---|---|---|---|---|---|---|
| Overall Capital reductions | Part C, Issue 24 | (102.5) | (133.5) | (153.5) | (132.3) | (143.3) |

**Table 1 - Number of Customers Forecast by Rate Class (Mid-Year)**

| Rate Class | 2023 | 2024 | 2025 | 2026 | 2027 |
|---|---|---|---|---|---|
| Dgen | 1,489 | 1,576 | 1,662 | 1,748 | 1,834 |
| GSd | 5,343 | 5,393 | 5,439 | 5,487 | 5,536 |
| GSe | 88,795 | 88,831 | 88,891 | 88,970 | 89,067 |
| R1 | 543,965 | 548,767 | 553,488 | 557,928 | 562,310 |
| R2 | 415,856 | 417,937 | 419,947 | 421,733 | 423,469 |
| ST | 910 | 917 | 924 | 931 | 938 |
| UGd | 1,743 | 1,753 | 1,764 | 1,775 | 1,786 |
| UGe | 18,432 | 18,524 | 18,620 | 18,720 | 18,824 |
| UR | 246,136 | 249,127 | 252,081 | 254,909 | 257,709 |
| STL | 5,494 | 5,536 | 5,577 | 5,615 | 5,654 |
| Sen LGT | 19,409 | 19,086 | 18,765 | 18,439 | 18,117 |
| USL | 5,752 | 5,793 | 5,832 | 5,869 | 5,906 |
| AR | 38,991 | 39,198 | 39,401 | 39,591 | 39,777 |
| AGSe | 4,223 | 4,213 | 4,203 | 4,193 | 4,183 |
| AGSd | 303 | 306 | 308 | 311 | 313 |
| AUR | 15,476 | 15,550 | 15,622 | 15,690 | 15,756 |
| AUGe | 1,380 | 1,392 | 1,404 | 1,416 | 1,427 |
| AUGd | 207 | 207 | 208 | 208 | 208 |
| Total | 1,413,905 | 1,424,106 | 1,434,135 | 1,443,532 | 1,452,813 |

**Table 2 – Sales Forecast by Rate Class (GWh)**

| Rate Class | 2023 | 2024 | 2025 | 2026 | 2027 |
|---|---|---|---|---|---|
| Dgen | 30 | 31 | 32 | 32 | 33 |
| GSd | 2,183 | 2,183 | 2,149 | 2,138 | 2,143 |
| GSe | 1,995 | 1,982 | 1,937 | 1,914 | 1,905 |
| R1 | 5,083 | 5,120 | 5,073 | 5,083 | 5,129 |
| R2 | 4,828 | 4,822 | 4,739 | 4,708 | 4,711 |
| ST | 15,070 | 15,126 | 15,011 | 15,004 | 15,090 |
| UGd | 883 | 885 | 872 | 868 | 871 |
| UGe | 547 | 547 | 538 | 535 | 535 |
| UR | 2,025 | 2,045 | 2,031 | 2,040 | 2,063 |
| STL | 83 | 83 | 81 | 81 | 80 |
| Sen LGT | 11 | 11 | 11 | 10 | 10 |
| USL | 33 | 33 | 33 | 33 | 33 |
| AR | 336 | 334 | 332 | 330 | 327 |
| AGSe | 117 | 116 | 115 | 114 | 113 |
| AGSd | 231 | 229 | 227 | 225 | 223 |
| AUR | 118 | 119 | 119 | 120 | 121 |
| AUGe | 41 | 41 | 42 | 42 | 43 |
| AUGd | 118 | 119 | 119 | 119 | 119 |
| Total | 33,735 | 33,826 | 33,460 | 33,396 | 33,548 |

**Table 3 – Forecast of Customer Billing Peak by Rate Class (12-month sum in kW)**

| Rate Class | 2023 | 2024 | 2025 | 2026 | 2027 |
|---|---|---|---|---|---|
| Dgen | 210,462 | 216,624 | 219,198 | 224,090 | 230,562 |
| GSd | 6,995,713 | 6,997,873 | 6,886,927 | 6,852,769 | 6,868,965 |
| GSe | | | | | |
| R1 | | | | | |
| R2 | | | | | |
| ST | 30,805,724 | 30,920,895 | 30,684,065 | 30,671,163 | 30,845,323 |
| UGd | 2,304,119 | 2,302,095 | 2,262,967 | 2,249,148 | 2,251,682 |
| UGe | | | | | |
| UR | | | | | |
| STL | | | | | |
| Sen LGT | | | | | |
| USL | | | | | |
| AR | | | | | |
| AGSe | | | | | |
| AGSd | 646,691 | 640,641 | 635,376 | 629,258 | 622,315 |
| AUR | | | | | |
| AUGe | | | | | |
| AUGd | 334,039 | 334,225 | 334,687 | 334,742 | 334,386 |
| Total | 41,296,748 | 41,412,352 | 41,023,220 | 40,961,169 | 41,153,231 |

# 2023 Cost Allocation Model

**EB-2021-0110**
**Sheet I6.1 Revenue Worksheet**

| | |
|---|---|
| Total kWhs from Load Forecast | 33,735,278,243 |
| Total kWs from Load Forecast | 41,296,748 |
| Deficiency/sufficiency ( RRWF 8. cell F51) | 66,575,074 |
| Miscellaneous Revenue (RRWF 5. cell F48) | 43,583,177 |

| | | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | ID | Total | UR | R1 | R2 | GSe | GSd | UGe | UGd | St Lgt | Sen Lgt | USL | DGen | ST | AUR | AUGe | AUGd | AR | AGSe | AGSd |
| **Billing Data** | | | | | | | | | | | | | | | | | | | | |
| Forecast kWh | CEN | 33,735,278,243 | 2,024,934,137 | 5,083,445,346 | 4,828,339,924 | 1,994,844,246 | 2,182,644,295 | 547,270,602 | 883,486,610 | 83,384,291 | 11,385,518 | 32,640,414 | 30,291,879 | 15,070,145,145 | 118,127,033 | 40,925,460 | 118,498,175 | 336,111,907 | 117,355,731 | 231,447,531 |
| Forecast kW | CDEM | 41,296,748 | - | - | - | - | 6,995,713 | - | 2,304,119 | - | - | - | 210,462 | 30,805,724 | - | - | 334,039 | - | - | 646,691 |
| Forecast kW, included in CDEM, of customers receiving line transformer allowance | | 2,259,340 | - | - | - | - | 1,133,898 | - | 504,192 | - | - | - | 171,770 | - | - | - | 175,742 | - | - | 273,737 |
| Optional - Forecast kWh, included in CEN, from customers that receive a line transformation allowance on a kWh basis. In most cases this will not be applicable and will be left blank. | | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| KWh excluding KWh from Wholesale Market Participants | CEN EWMP | 24,082,063,820 | 2,024,934,137 | 5,083,445,346 | 4,828,339,924 | 1,994,844,246 | 2,175,237,254 | 547,270,602 | 881,269,056 | 83,384,291 | 11,385,518 | 32,640,414 | 30,171,525 | 5,434,405,384 | 118,127,033 | 40,925,460 | 115,975,284 | 336,111,907 | 117,355,731 | 226,240,707 |
| | | | | | | | | | | | | | | | | | | | | |
| Existing Monthly Charge | | | $38.05 | $56.34 | $115.27 | $34.13 | $113.67 | $26.95 | $104.78 | $11.16 | $3.25 | $39.31 | $199.36 | $1,175.74 | $31.42 | $26.36 | $146.47 | $38.15 | $39.96 | $170.26 |
| Existing Distribution kWh Rate | | | $0.0000 | $0.0111 | $0.0171 | $0.0680 | | $0.0324 | | $0.1064 | $0.1703 | $0.0260 | | | $0.0000 | $0.0152 | | $0.0000 | $0.0183 | |
| Existing Distribution kW Rate | | | | | | | $19.3086 | | $11.1067 | | | | $10.9438 | $1.6658 | | | $2.2574 | | | $3.8703 |
| Existing TFOA Rate | | | | | | | | | | | | | | | | | | | | |
| Additional Charges | | | | | | | | | | | | | | | | | | | | |
| Distribution Revenue from Rates | | $1,679,269,721 | $112,385,899 | $424,190,011 | $657,792,973 | $172,016,255 | $142,364,944 | $23,692,482 | $27,782,698 | 9,607,833 | $2,695,922 | $3,562,181 | $5,866,195 | $64,155,257 | $5,835,145 | $1,058,620 | $1,118,418 | $17,850,048 | $4,172,554 | $3,122,287 |
| Transformer Ownership Allowance | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| Net Class Revenue | CREV | $1,679,269,721 | $112,385,899 | $424,190,011 | $657,792,973 | $172,016,255 | $142,364,944 | $23,692,482 | $27,782,698 | $9,607,833 | $2,695,922 | $3,562,181 | $5,866,195 | $64,155,257 | $5,835,145 | $1,058,620 | $1,118,418 | $17,850,048 | $4,172,554 | $3,122,287 |

# 2023 Cost Allocation Model

**EB-2021-0110**

**Sheet I6.2 Customer Data Worksheet**

| | | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | ID | Total | UR | R1 | R2 | GSe | GSd | UGe | UGd | St Lgt | Sen Lgt | USL | DGen | ST | AUR | AUGe | AUGd | AR | AGSe | AGSd |
| **Billing Data** | | | | | | | | | | | | | | | | | | | | |
| Bad Debt 3 Year Historical Average | BDHA | $24,828,191 | $3,018,703 | $9,861,898 | $6,488,975 | $1,842,062 | $2,020,921 | $304,756 | $363,043 | $26,287 | $34,214 | $6,754 | $3,981 | $159,609 | $205,917 | $22,476 | $38,004 | $361,471 | $48,184 | $20,937 |
| Late Payment 3 Year Historical Average | LPHA | $12,866,261 | 1,570,155 | 4,196,700 | 3,515,705 | 1,212,049 | 787,336 | 237,497 | 189,978 | 25,799 | 17,606 | 10,832 | 36,441 | 606,056 | 90,258 | 11,306 | 31,144 | 224,423 | 45,479 | 57,498 |
| Number of Bills | CNB | 15,709,197 | 2,951,789 | 6,017,635 | 4,360,852 | 1,065,539 | 64,111 | 221,184 | 20,916 | 65,927 | 116,457 | 69,029 | 17,872 | 10,920 | 185,714 | 16,561 | 2,488 | 467,891 | 50,674 | 3,638 |
| Number of Devices | | | | | | | | | | 165,226 | | | | | | | | | | |
| Number of Connections (Unmetered) | CCON | 36,110 | - | - | - | - | - | - | - | 20,653 | 9,705 | 5,752 | - | - | - | - | - | - | - | - |
| Total Number of Customers | CCA | 1,419,360 | 246,136 | 543,965 | 415,856 | 88,795 | 5,343 | 18,432 | 1,743 | 20,653 | 9,705 | 5,752 | 1,489 | 910 | 15,476 | 1,380 | 207 | 38,991 | 4,223 | 303 |
| Bulk Customer Base | CCB | 1,419,360 | 246,136 | 543,965 | 415,856 | 88,795 | 5,343 | 18,432 | 1,743 | 20,653 | 9,705 | 5,752 | 1,489 | 910 | 15,476 | 1,380 | 207 | 38,991 | 4,223 | 303 |
| Primary Customer Base | CCP | 1,412,847 | 246,136 | 543,965 | 415,856 | 88,795 | 5,343 | 18,432 | 1,743 | 14,962 | 9,705 | 5,752 | 751 | 827 | 15,476 | 1,380 | 207 | 38,991 | 4,223 | 303 |
| Line Transformer Customer Base | CCLT | 1,410,838 | 246,136 | 543,965 | 415,856 | 88,795 | 4,854 | 18,432 | 1,522 | 14,962 | 9,705 | 5,752 | 380 | - | 15,476 | 1,380 | 162 | 38,991 | 4,223 | 248 |
| Secondary Customer Base | CCS | 1,409,364 | 246,136 | 543,965 | 415,856 | 88,795 | - | 18,432 | - | 20,653 | 9,705 | 5,752 | - | - | 15,476 | 1,380 | - | 38,991 | 4,223 | - |
| Weighted - Services | CWCS | 1,191,807 | 123,068 | 407,974 | 623,784 | - | - | - | - | - | - | - | - | - | 7,738 | - | - | 29,243 | - | - |
| Weighted Meter Capital | CWMC | 657,843,048 | 100,478,042 | 224,286,833 | 177,713,362 | 65,666,744 | 17,531,672 | 20,301,682 | 5,074,940 | - | - | - | 13,999,850 | 7,283,126 | 6,778,816 | 1,490,297 | 406,033 | 13,092,281 | 2,899,251 | 840,119 |
| Weighted Meter Reading | CWMR | 256,510 | 1,898 | 17,445 | 174,989 | 42,547 | 11,618 | 3,195 | 1,949 | - | - | - | - | - | 59 | 185 | 121 | 291 | 462 | 1,752 |
| Weighted Bills | CWNB | 15,806,721 | 2,951,789 | 6,017,635 | 4,360,852 | 1,074,602 | 129,361 | 223,066 | 42,203 | 63,211 | 111,169 | 65,353 | 17,010 | 16,697 | 185,714 | 16,702 | 5,019 | 467,891 | 51,105 | 7,341 |

## Bad Debt Data

| | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Historic Year: | 2017 | 28,020,663 | 3,752,210 | 9,389,383 | 9,078,160 | 2,597,262 | 878,058 | 339,323 | 654,903 | 370 | 38,716 | 1,026 | 3,500 | 379,384 | 259,231 | 34,387 | 67,954 | 423,571 | 62,451 | 60,773 |
| Historic Year: | 2018 | 28,080,302 | 2,455,529 | 13,441,313 | 4,951,476 | 1,808,714 | 4,503,612 | 211,951 | 41,913 | 76,847 | 38,783 | 17,982 | 848 | 40,000 | 154,680 | 14,628 | 16,842 | 289,941 | 15,243 | - |
| Historic Year: | 2019 | 18,383,610 | 2,848,369 | 6,754,998 | 5,437,290 | 1,120,210 | 681,092 | 362,994 | 392,312 | 1,644 | 25,142 | 1,254 | 7,594 | 59,444 | 203,839 | 18,413 | 29,215 | 370,902 | 66,859 | 2,037 |
| Three-year average | | **24,828,191** | **3,018,703** | **9,861,898** | **6,488,975** | **1,842,062** | **2,020,921** | **304,756** | **363,043** | **26,287** | **34,214** | **6,754** | **3,981** | **159,609** | **205,917** | **22,476** | **38,004** | **361,471** | **48,184** | **20,937** |

## Street Lighting Adjustment Factors

| NCP Test Results | 4 NCP |
|---|---|

| | Primary Asset Data | | Line Transformer Asset Data | |
|---|---|---|---|---|
| Class | Customers/ Devices | 4 NCP | Customers/ Devices | 4 NCP |
| UR | 246,136 | 1,884,385 | 246,136 | 1,884,385 |
| R1 | 543,965 | 4,176,928 | 543,965 | 4,176,928 |
| R2 | 415,856 | 3,984,901 | 415,856 | 3,984,901 |
| AUR | 15,476 | 119,470 | 15,476 | 119,470 |
| AR | 38,991 | 315,601 | 38,991 | 315,601 |
| Street Light | 165,226 | 124,416 | 165,226 | 124,416 |

| Street Lighting Adjustment Factors | |
|---|---|
| Primary | 11.04 |
| Line Transformer | 11.04 |

# 2023 Cost Allocation Model

**EB-2021-0110**

**Sheet I8 Demand Data Worksheet**

This is an input sheet for demand allocators.

| | |
|---|---|
| CP TEST RESULTS | 12 CP |
| NCP TEST RESULTS | 4 NCP |

| Co-incident Peak | Indicator |
|---|---|
| 1 CP | CP 1 |
| 4 CP | CP 4 |
| 12 CP | CP 12 |

| Non-co-incident Peak | Indicator |
|---|---|
| 1 NCP | NCP 1 |
| 4 NCP | NCP 4 |
| 12 NCP | NCP 12 |

| | | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Customer Classes** | | **Total** | **UR** | **R1** | **R2** | **GSe** | **GSd** | **UGe** | **UGd** | **St Lgt** | **Sen Lgt** | **USL** | **DGen** | **ST** | **AUR** | **AUGe** | **AUGd** | **AR** | **AGSe** | **AGSd** |
| **CO-INCIDENT PEAK** | | | | | | | | | | | | | | | | | | | | |
| **1 CP** | | | | | | | | | | | | | | | | | | | | |
| Transformation CP | TCP1 | 6,050,021 | 449,339 | 1,202,334 | 1,183,363 | 350,504 | 286,836 | 93,985 | 128,295 | 15,394 | 2,145 | 4,037 | 6,035 | 2,173,063 | 23,718 | 5,595 | 12,561 | 71,715 | 16,593 | 24,510 |
| Bulk Delivery CP | BCP1 | 5,857,995 | 434,886 | 1,164,342 | 1,146,952 | 339,630 | 277,644 | 90,990 | 124,141 | 14,914 | 2,078 | 3,911 | 5,837 | 2,101,641 | 23,319 | 5,501 | 12,342 | 69,835 | 16,158 | 23,875 |
| Total Sytem CP | DCP1 | 6,050,021 | 449,339 | 1,202,334 | 1,183,363 | 350,504 | 286,836 | 93,985 | 128,295 | 15,394 | 2,145 | 4,037 | 6,035 | 2,173,063 | 23,718 | 5,595 | 12,561 | 71,715 | 16,593 | 24,510 |
| **4 CP** | | | | | | | | | | | | | | | | | | | | |
| Transformation CP | TCP4 | 23,144,620 | 1,864,579 | 4,272,290 | 3,899,039 | 1,331,374 | 1,217,066 | 370,383 | 527,317 | 38,143 | 5,033 | 16,297 | 15,305 | 8,874,629 | 111,055 | 26,382 | 67,577 | 314,801 | 77,986 | 115,365 |
| Bulk Delivery CP | BCP4 | 22,409,676 | 1,804,602 | 4,137,292 | 3,779,068 | 1,290,072 | 1,178,065 | 358,581 | 510,242 | 36,955 | 4,877 | 15,789 | 14,803 | 8,582,949 | 109,184 | 25,937 | 66,395 | 306,549 | 75,941 | 112,374 |
| Total Sytem CP | DCP4 | 23,144,620 | 1,864,579 | 4,272,290 | 3,899,039 | 1,331,374 | 1,217,066 | 370,383 | 527,317 | 38,143 | 5,033 | 16,297 | 15,305 | 8,874,629 | 111,055 | 26,382 | 67,577 | 314,801 | 77,986 | 115,365 |
| **12 CP** | | | | | | | | | | | | | | | | | | | | |
| Transformation CP | TCP12 | 63,805,647 | 4,623,814 | 11,228,220 | 10,466,492 | 3,697,608 | 3,647,724 | 1,015,886 | 1,510,549 | 106,001 | 14,550 | 48,930 | 50,180 | 25,532,907 | 269,606 | 72,240 | 193,911 | 766,911 | 213,025 | 347,095 |
| Bulk Delivery CP | BCP12 | 61,777,249 | 4,475,082 | 10,873,425 | 10,144,446 | 3,582,901 | 3,530,832 | 983,515 | 1,461,636 | 102,700 | 14,097 | 47,406 | 48,534 | 24,693,723 | 265,064 | 71,023 | 190,518 | 746,807 | 207,440 | 338,099 |
| Total Sytem CP | DCP12 | 63,805,647 | 4,623,814 | 11,228,220 | 10,466,492 | 3,697,608 | 3,647,724 | 1,015,886 | 1,510,549 | 106,001 | 14,550 | 48,930 | 50,180 | 25,532,907 | 269,606 | 72,240 | 193,911 | 766,911 | 213,025 | 347,095 |
| **NON CO_INCIDENT PEAK** | | | | | | | | | | | | | | | | | | | | |
| **1 NCP** | | | | | | | | | | | | | | | | | | | | |
| Classification NCP from Load Data Provider | DNCP1 | 6,621,881 | 541,809 | 1,202,334 | 1,188,622 | 397,509 | 393,527 | 114,537 | 154,493 | 37,079 | 4,871 | 4,276 | 9,316 | 2,345,233 | 34,319 | 9,356 | 22,084 | 93,341 | 26,180 | 42,996 |
| Primary NCP | PNCP1 | 4,110,339 | 519,022 | 1,142,257 | 1,116,496 | 374,709 | 370,902 | 109,238 | 147,136 | 35,008 | 4,599 | 4,037 | 899 | 68,012 | 33,250 | 9,064 | 21,379 | 88,639 | 24,861 | 40,832 |
| Line Transformer NCP | LTNCP1 | 3,920,748 | 519,022 | 1,142,257 | 1,116,496 | 374,709 | 310,784 | 109,238 | 114,939 | 35,008 | 4,599 | 4,037 | 165 | - | 33,250 | 9,064 | 10,131 | 88,639 | 24,861 | 23,548 |
| Secondary NCP | SNCP1 | 3,372,251 | 512,591 | 1,117,411 | 1,075,676 | 362,691 | - | 107,344 | - | 33,955 | 4,461 | 3,916 | - | - | 32,904 | 8,970 | - | 87,726 | 24,605 | - |
| **4 NCP** | | | | | | | | | | | | | | | | | | | | |
| Classification NCP from Load Data Provider | DNCP4 | 24,899,664 | 1,967,117 | 4,396,615 | 4,242,327 | 1,521,364 | 1,509,894 | 442,005 | 602,519 | 131,777 | 17,916 | 16,701 | 35,960 | 9,173,658 | 123,313 | 34,822 | 85,796 | 332,343 | 97,866 | 167,670 |
| Primary NCP | PNCP4 | 15,129,425 | 1,884,385 | 4,176,928 | 3,984,901 | 1,434,104 | 1,423,086 | 421,557 | 573,828 | 124,416 | 16,915 | 15,768 | 3,469 | 266,037 | 119,470 | 33,737 | 83,055 | 315,601 | 92,936 | 159,231 |
| Line Transformer NCP | LTNCP4 | 14,393,234 | 1,884,385 | 4,176,928 | 3,984,901 | 1,434,104 | 1,192,426 | 421,557 | 448,261 | 124,416 | 16,915 | 15,768 | 638 | - | 119,470 | 33,737 | 39,359 | 315,601 | 92,936 | 91,830 |
| Secondary NCP | SNCP4 | 12,297,000 | 1,861,038 | 4,086,073 | 3,839,210 | 1,388,106 | - | 414,250 | - | 120,675 | 16,406 | 15,294 | - | - | 118,229 | 33,387 | - | 312,352 | 91,979 | - |
| **12 NCP** | | | | | | | | | | | | | | | | | | | | |
| Classification NCP from Load Data Provider | DNCP12 | 67,941,031 | 5,034,721 | 11,755,730 | 10,907,548 | 4,180,055 | 4,347,875 | 1,213,238 | 1,734,874 | 308,301 | 41,934 | 49,124 | 92,359 | 26,107,347 | 302,473 | 92,852 | 243,288 | 819,852 | 252,336 | 457,124 |
| Primary NCP | PNCP12 | 40,298,445 | 4,822,974 | 11,168,329 | 10,245,674 | 3,940,304 | 4,097,903 | 1,157,110 | 1,652,261 | 291,079 | 39,592 | 46,380 | 8,909 | 757,115 | 293,048 | 89,959 | 235,516 | 778,551 | 239,624 | 434,116 |
| Line Transformer NCP | LTNCP12 | 38,200,636 | 4,822,974 | 11,168,329 | 10,245,674 | 3,940,304 | 3,433,695 | 1,157,110 | 1,290,709 | 291,079 | 39,592 | 46,380 | 1,638 | - | 293,048 | 89,959 | 111,608 | 778,551 | 239,624 | 250,360 |
| Secondary NCP | SNCP12 | 32,263,111 | 4,763,218 | 10,925,400 | 9,871,084 | 3,813,919 | - | 1,137,055 | - | 282,327 | 38,401 | 44,985 | - | - | 290,003 | 89,024 | - | 770,537 | 237,158 | - |

# 2023 Cost Allocation Model

**EB-2021-0110**

**Sheet O1 Revenue to Cost Summary Worksheet**

**Instructions:**
Please see the first tab in this workbook for detailed instructions

**Class Revenue, Cost Analysis, and Return on Rate Base**

| Rate Base Assets | | Total | 1 UR | 2 R1 | 3 R2 | 4 GSe | 5 GSd | 6 UGe | 7 UGd | 8 St Lgt | 9 Sen Lgt | 10 USL | 11 DGen | 12 ST | 13 AUR | 14 AUGe | 15 AUGd | 16 AR | 17 AGSe | 18 AGSd |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| crev | Distribution Revenue at Existing Rates | $1,679,269,721 | $112,385,899 | $424,190,011 | $657,792,973 | $172,016,255 | $142,364,944 | $23,692,482 | $27,782,698 | $9,607,833 | $2,695,922 | $3,562,181 | $5,866,195 | $64,155,257 | $5,835,145 | $1,058,620 | $1,118,418 | $17,850,048 | $4,172,554 | $3,122,287 |
| mi | Miscellaneous Revenue (mi) | $43,583,177 | $4,387,276 | $12,021,983 | $14,737,593 | $3,614,492 | $2,124,771 | $590,543 | $439,538 | $247,580 | $2,735,960 | $86,988 | $77,487 | $1,258,437 | $261,832 | $33,236 | $41,359 | $719,016 | $114,255 | $90,831 |
| | | Miscellaneous Revenue Input equals Output | | | | | | | | | | | | | | | | | | |
| | **Total Revenue at Existing Rates** | $1,722,852,898 | $116,773,176 | $436,211,993 | $672,530,567 | $175,630,747 | $144,489,715 | $24,283,025 | $28,222,236 | $9,855,413 | $5,431,882 | $3,649,169 | $5,943,682 | $65,413,693 | $6,096,977 | $1,091,856 | $1,159,777 | $18,569,064 | $4,286,809 | $3,213,118 |
| | Factor required to recover deficiency (1 + D) | 0.9604 | | | | | | | | | | | | | | | | | | |
| | Distribution Revenue at Status Quo Rates | $1,612,694,647 | $107,930,332 | $407,372,890 | $631,714,604 | $165,196,627 | $136,720,849 | $22,753,188 | $26,681,246 | $9,226,928 | $2,589,041 | $3,420,958 | $5,633,628 | $61,611,805 | $5,603,809 | $1,016,651 | $1,074,078 | $17,142,378 | $4,007,132 | $2,998,503 |
| | Miscellaneous Revenue (mi) | $43,583,177 | $4,387,276 | $12,021,983 | $14,737,593 | $3,614,492 | $2,124,771 | $590,543 | $439,538 | $247,580 | $2,735,960 | $86,988 | $77,487 | $1,258,437 | $261,832 | $33,236 | $41,359 | $719,016 | $114,255 | $90,831 |
| | **Total Revenue at Status Quo Rates** | $1,656,277,824 | $112,317,608 | $419,394,873 | $646,452,197 | $168,811,119 | $138,845,620 | $23,343,731 | $27,120,784 | $9,474,508 | $5,325,001 | $3,507,945 | $5,711,115 | $62,870,242 | $5,865,642 | $1,049,887 | $1,115,437 | $17,861,395 | $4,121,387 | $3,089,334 |
| | **Expenses** | | | | | | | | | | | | | | | | | | | |
| di | Distribution Costs (di) | $291,048,265 | $15,219,004 | $63,137,399 | $135,174,246 | $27,685,716 | $20,835,718 | $3,269,098 | $3,826,523 | $2,126,634 | $905,780 | $602,513 | $130,053 | $12,349,929 | $867,158 | $167,255 | $166,135 | $3,429,270 | $619,201 | $536,634 |
| cu | Customer Related Costs (cu) | $136,745,875 | $21,280,369 | $48,087,095 | $42,564,278 | $11,035,555 | $3,117,371 | $2,180,843 | $699,038 | $656,342 | $634,856 | $384,400 | $517,718 | $416,436 | $1,308,590 | $147,422 | $64,369 | $3,126,350 | $398,598 | $146,244 |
| ad | General and Administration (ad) | $178,401,000 | $14,757,927 | $45,520,645 | $73,988,759 | $16,335,786 | $10,721,445 | $2,299,731 | $2,023,650 | $1,149,805 | $624,263 | $394,212 | $364,895 | $5,697,634 | $876,980 | $131,329 | $109,292 | $2,671,175 | $427,477 | $305,993 |
| dep | Depreciation and Amortization (dep) | $461,417,513 | $27,091,698 | $96,469,587 | $184,835,801 | $49,074,435 | $50,093,959 | $7,638,386 | $9,209,852 | $2,456,635 | $1,332,552 | $678,481 | $1,326,493 | $20,298,170 | $1,560,478 | $438,417 | $558,980 | $5,401,170 | $1,409,473 | $1,542,944 |
| INPUT | PILs (INPUT) | $39,794,572 | $2,010,844 | $7,871,109 | $16,548,080 | $4,311,288 | $4,405,146 | $609,728 | $804,444 | $231,259 | $88,612 | $63,403 | $57,601 | $1,975,153 | $110,864 | $30,459 | $33,931 | $425,786 | $107,133 | $109,731 |
| INT | Interest | $221,478,424 | $11,191,440 | $43,807,002 | $92,099,060 | $23,994,663 | $24,517,031 | $3,393,468 | $4,477,171 | $1,287,081 | $493,172 | $352,872 | $320,580 | $10,992,801 | $617,020 | $169,523 | $188,845 | $2,369,730 | $596,254 | $610,712 |
| | **Total Expenses** | $1,328,885,648 | $91,551,282 | $304,892,837 | $545,210,224 | $132,437,442 | $113,690,671 | $19,391,253 | $21,040,678 | $7,907,755 | $4,079,235 | $2,455,881 | $2,717,341 | $51,730,123 | $5,341,090 | $1,084,406 | $1,121,552 | $17,423,482 | $3,558,136 | $3,252,259 |
| | **Direct Allocation** | $11,805,407 | $0 | $0 | $0 | $0 | $2,148,541 | $0 | $671,221 | $0 | $0 | $0 | $3,719,561 | $5,007,622 | $0 | $0 | $120,708 | $0 | $0 | $137,754 |
| NI | Allocated Net Income (NI) | $315,586,769 | $15,946,792 | $62,421,025 | $131,232,850 | $34,190,230 | $34,934,557 | $4,835,385 | $6,379,564 | $1,833,974 | $702,726 | $502,810 | $456,797 | $15,663,750 | $879,197 | $241,555 | $269,087 | $3,376,652 | $849,607 | $870,210 |
| | **Revenue Requirement (includes NI)** | $1,656,277,824 | $107,498,074 | $367,313,862 | $676,443,073 | $166,627,672 | $150,773,769 | $24,226,639 | $28,091,463 | $9,741,729 | $4,781,961 | $2,958,691 | $6,893,699 | $72,401,495 | $6,220,287 | $1,325,961 | $1,511,348 | $20,800,134 | $4,407,744 | $4,260,223 |
| | | Revenue Requirement Input equals Output | | | | | | | | | | | | | | | | | | |
| | **Rate Base Calculation** | | | | | | | | | | | | | | | | | | | |
| | **Net Assets** | | | | | | | | | | | | | | | | | | | |
| dp | Distribution Plant - Gross | $14,152,448,547 | $718,058,666 | $2,770,410,340 | $5,722,242,126 | $1,455,000,869 | $1,512,046,720 | $207,821,845 | $276,148,018 | $77,990,548 | $30,070,956 | $21,355,761 | $20,608,135 | $662,114,346 | $104,085,104 | $31,578,220 | $59,739,671 | $278,351,684 | $84,980,555 | $119,844,986 |
| gp | General Plant - Gross | $1,235,719,872 | $61,398,005 | $241,355,858 | $508,523,901 | $131,720,221 | $134,687,706 | $18,549,141 | $24,567,748 | $7,110,739 | $18,809,982 | $1,954,783 | $1,666,941 | $60,309,940 | $3,396,537 | $930,693 | $1,036,010 | $13,072,691 | $3,276,573 | $3,352,404 |
| accum dep | Accumulated Depreciation | ($5,210,817,890) | ($278,456,811) | ($1,044,862,994) | ($2,097,481,904) | ($524,767,010) | ($559,816,919) | ($76,901,145) | ($102,516,366) | ($27,637,426) | ($21,032,642) | ($7,496,686) | ($8,918,767) | ($234,226,266) | ($34,468,141) | ($10,265,987) | ($19,295,852) | ($95,077,838) | ($27,909,068) | ($39,686,068) |
| co | Capital Contribution | ($1,252,826,825) | ($62,484,633) | ($250,042,750) | ($523,392,809) | ($121,739,693) | ($126,198,701) | ($16,527,617) | ($22,768,104) | ($7,014,293) | ($3,372,962) | ($1,980,492) | ($827,876) | ($57,465,451) | ($9,170,553) | ($2,629,552) | ($4,926,923) | ($25,201,728) | ($7,155,458) | ($9,927,228) |
| | **Total Net Plant** | $8,924,523,704 | $438,515,227 | $1,716,860,454 | $3,609,891,313 | $940,214,387 | $960,718,806 | $132,942,225 | $175,431,296 | $50,449,567 | $24,475,333 | $13,833,366 | $12,528,432 | $430,732,569 | $63,842,947 | $19,613,373 | $36,552,905 | $171,144,808 | $53,192,601 | $73,584,094 |
| | **Directly Allocated Net Fixed Assets** | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| COP | Cost of Power (COP) | $3,422,780,409 | $287,803,610 | $722,509,386 | $686,251,287 | $283,526,938 | $309,166,171 | $77,783,495 | $125,254,649 | $11,851,398 | $1,618,222 | $4,639,178 | $4,288,275 | $772,391,288 | $16,789,379 | $5,816,730 | $16,483,551 | $47,771,539 | $16,679,754 | $32,155,560 |
| | OM&A Expenses | $606,195,140 | $51,257,300 | $156,745,139 | $251,727,283 | $55,057,056 | $34,674,535 | $7,749,672 | $6,549,211 | $3,932,781 | $2,164,899 | $1,361,125 | $1,012,667 | $18,463,999 | $3,052,729 | $446,007 | $339,796 | $9,226,795 | $1,445,276 | $988,871 |
| | Directly Allocated Expenses | $11,805,407 | $0 | $0 | $0 | $0 | $2,148,541 | $0 | $671,221 | $0 | $0 | $0 | $3,719,561 | $5,007,622 | $0 | $0 | $120,708 | $0 | $0 | $137,754 |
| | ***Subtotal*** | $4,040,780,956 | $339,060,910 | $879,254,525 | $937,978,571 | $338,583,994 | $345,989,247 | $85,533,167 | $132,475,080 | $15,784,178 | $3,783,121 | $6,000,303 | $9,020,502 | $795,862,909 | $19,842,107 | $6,262,737 | $16,944,055 | $56,998,334 | $18,125,030 | $33,282,186 |
| | **Working Capital** | $249,764,961 | $20,957,715 | $54,347,656 | $57,977,451 | $20,928,236 | $21,385,963 | $5,286,896 | $8,188,425 | $975,637 | $233,839 | $370,885 | $557,567 | $49,193,131 | $1,226,462 | $387,106 | $1,047,330 | $3,523,128 | $1,120,327 | $2,057,207 |
| | **Total Rate Base** | $9,174,288,664 | $459,472,941 | $1,771,208,110 | $3,667,868,764 | $961,142,623 | $982,104,768 | $138,229,121 | $183,619,721 | $51,425,204 | $24,709,172 | $14,204,251 | $13,085,999 | $479,925,700 | $65,069,409 | $20,000,479 | $37,600,235 | $174,667,936 | $54,312,929 | $75,641,301 |
| | | Rate Base Input Does Not Equal Output | | | | | | | | | | | | | | | | | | |
| | **Equity Component of Rate Base** | $3,669,715,466 | $183,789,177 | $708,483,244 | $1,467,147,506 | $384,457,049 | $392,841,907 | $55,291,648 | $73,447,888 | $20,570,082 | $9,883,669 | $5,681,701 | $5,234,400 | $191,970,280 | $26,027,764 | $8,000,192 | $15,040,094 | $69,867,174 | $21,725,172 | $30,256,520 |
| | **Net Income on Allocated Assets** | $315,586,769 | $20,766,326 | $114,502,036 | $101,241,974 | $36,373,676 | $23,006,408 | $3,952,477 | $5,408,886 | $1,566,752 | $1,245,766 | $1,052,064 | ($725,787) | $6,132,497 | $524,552 | ($34,519) | ($126,823) | $437,913 | $563,251 | ($300,679) |
| | **Net Income on Direct Allocation Assets** | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | **Net Income** | $315,586,769 | $20,766,326 | $114,502,036 | $101,241,974 | $36,373,676 | $23,006,408 | $3,952,477 | $5,408,886 | $1,566,752 | $1,245,766 | $1,052,064 | ($725,787) | $6,132,497 | $524,552 | ($34,519) | ($126,823) | $437,913 | $563,251 | ($300,679) |
| | **RATIOS ANALYSIS** | | | | | | | | | | | | | | | | | | | |
| | **REVENUE TO EXPENSES STATUS QUO%** | 100.00% | 1.04 | 1.14 | 0.96 | 1.01 | 0.92 | 0.96 | 0.97 | 0.97 | 1.11 | 1.19 | 0.83 | 0.87 | 0.94 | 0.79 | 0.74 | 0.86 | 0.94 | 0.73 |
| | EXISTING REVENUE MINUS ALLOCATED COSTS | $66,575,074 | $9,275,102 | $68,898,131 | ($3,912,507) | $9,003,075 | ($6,284,055) | $56,386 | $130,773 | $113,683 | $649,921 | $690,477 | ($950,017) | ($6,987,802) | ($123,310) | ($234,105) | ($351,571) | ($2,231,069) | ($120,935) | ($1,047,105) |
| | | Deficiency Input equals Output | | | | | | | | | | | | | | | | | | |
| | STATUS QUO REVENUE MINUS ALLOCATED COSTS | $0 | $4,819,534 | $52,081,011 | ($29,990,876) | $2,183,447 | ($11,928,149) | ($882,908) | ($970,679) | ($267,222) | $543,040 | $549,254 | ($1,182,584) | ($9,531,253) | ($354,646) | ($276,074) | ($395,911) | ($2,938,739) | ($286,357) | ($1,170,888) |
| | RETURN ON EQUITY COMPONENT OF RATE BASE | 8.60% | 11.30% | 16.16% | 6.90% | 9.46% | 5.86% | 7.15% | 7.36% | 7.62% | 12.60% | 18.52% | -13.87% | 3.19% | 2.02% | -0.43% | -0.84% | 0.63% | 2.59% | -0.99% |

| | |
|---|---|
| Total Gross Plant including USoAs 1600s, 1700s and 2040 | $16,193,286,903 |
| Total Accumulated Depreciation including USoAs 1600s, 1700s and 2040 | ($5,737,626,787) |
| Total Capital Contributions | ($1,245,390,036) |
| Total Net Plant | $9,210,270,080 |
| Working Captial | $249,764,961 |
| Total Rate Base | $9,460,035,041 |
| Rate Base from I3 TB Data Sheet | $9,460,035,041 |
| | Rate Base Input Equals Output |

# 2023 Cost Allocation Model

**EB-2021-0110**

**Sheet O2 Monthly Fixed Charge Min. & Max. Worksheet**

**Output sheet showing minimum and maximum level for Monthly Fixed Charge**

## Summary

| | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | UR | R1 | R2 | GSe | GSd | UGe | UGd | St Lgt | Sen Lgt | USL | DGen | ST | AUR | AUGe | AUGd | AR | AGSe | AGSd |
| Customer Unit Cost per month - Avoided Cost | $9.41 | $9.19 | $10.61 | $14.61 | $44.45 | $17.81 | $39.12 | $2.37 | $4.70 | $4.67 | $114.70 | $54.46 | $8.61 | $14.67 | $16.40 | $7.93 | $11.14 | $41.31 |
| Customer Unit Cost per month - Directly Related | $12.20 | $11.95 | $13.97 | $18.90 | $58.36 | $22.30 | $50.51 | $3.39 | $6.66 | $6.63 | $138.25 | $73.22 | $11.08 | $18.05 | $23.27 | $10.39 | $14.20 | $57.70 |
| Customer Unit Cost per month - Minimum System with PLCC Adjustment | $22.46 | $29.72 | $54.00 | $21.53 | $58.07 | $13.35 | $52.73 | $15.27 | $16.70 | $35.83 | $143.65 | $59.88 | $21.59 | $7.04 | $33.25 | $23.87 | $5.04 | $53.25 |
| Existing Approved Fixed Charge | $38.05 | $56.34 | $115.27 | $34.13 | $113.67 | $26.95 | $104.78 | $11.16 | $3.25 | $39.31 | $199.36 | $1,175.74 | $31.42 | $26.36 | $146.47 | $38.15 | $39.96 | $170.26 |

| Information to be Used to Allocate PILs, ROD, | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 |
|---|---|---|---|---|---|---|---|---|---|---|
| | Total | UR | R1 | R2 | GSe | GSd | UGe | UGd | St Lgt | Sen Lgt |
| General Plant - Gross Assets | $1,235,719,872 | $61,398,005 | $241,355,858 | $508,523,901 | $131,720,221 | $134,687,706 | $18,549,141 | $24,567,748 | $7,110,739 | $18,809,982 |
| General Plant - Accumulated Depreciation | ($793,821,543) | ($39,411,243) | ($154,925,791) | ($326,420,365) | ($84,550,918) | ($86,455,740) | ($11,906,653) | ($15,769,983) | ($4,564,367) | ($12,689,781) |
| General Plant - Net Fixed Assets | $441,898,328 | $21,986,761 | $86,430,067 | $182,103,535 | $47,169,303 | $48,231,966 | $6,642,489 | $8,797,765 | $2,546,371 | $6,120,202 |
| General Plant - Depreciation | $113,611,315 | $5,701,471 | $22,412,511 | $47,221,963 | $12,231,652 | $12,507,215 | $1,722,489 | $2,281,382 | $660,309 | $608,024 |
| Total Net Fixed Assets Excluding General Plant | $8,482,625,376 | $416,528,465 | $1,630,430,387 | $3,427,787,778 | $893,045,084 | $912,486,840 | $126,299,736 | $166,633,531 | $47,903,196 | $18,355,132 |
| Total Administration and General Expense | $178,401,000 | $14,757,927 | $45,520,645 | $73,988,759 | $16,335,786 | $10,721,445 | $2,299,731 | $2,023,650 | $1,149,805 | $624,263 |
| Total O&M | $427,794,139 | $36,499,373 | $111,224,494 | $177,738,524 | $38,721,270 | $23,953,089 | $5,449,941 | $4,525,561 | $2,782,976 | $1,540,635 |

| Information to be Used to Allocate PILs, ROD, | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 |
|---|---|---|---|---|---|---|---|---|---|
| | USL | DGen | ST | AUR | AUGe | AUGd | AR | AGSe | AGSd |
| General Plant - Gross Assets | $1,954,783 | $1,666,941 | $60,309,940 | $3,396,537 | $930,693 | $1,036,010 | $13,072,691 | $3,276,573 | $3,352,404 |
| General Plant - Accumulated Depreciation | ($1,254,771) | ($1,070,006) | ($38,712,817) | ($2,180,230) | ($597,410) | ($665,012) | ($8,391,331) | ($2,103,225) | ($2,151,901) |
| General Plant - Net Fixed Assets | $700,012 | $596,935 | $21,597,123 | $1,216,308 | $333,283 | $370,997 | $4,681,359 | $1,173,348 | $1,200,503 |
| General Plant - Depreciation | $181,523 | $154,794 | $5,600,432 | $315,405 | $86,425 | $96,205 | $1,213,941 | $304,265 | $311,307 |
| Total Net Fixed Assets Excluding General Plant | $13,133,354 | $11,931,497 | $409,135,446 | $62,626,640 | $19,280,090 | $36,181,908 | $166,463,449 | $52,019,253 | $72,383,591 |
| Total Administration and General Expense | $394,212 | $364,895 | $5,697,634 | $876,980 | $131,329 | $109,292 | $2,671,175 | $427,477 | $305,993 |
| Total O&M | $966,913 | $647,771 | $12,766,365 | $2,175,748 | $314,677 | $230,504 | $6,555,620 | $1,017,799 | $682,878 |

## Scenario 1

***Accounts included in Avoided Costs Plus General Administration  Allocation***

| | | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **USoA Account #** | **Accounts** | **Total** | **UR** | **R1** | **R2** | **GSe** | **GSd** | **UGe** | **UGd** | **St Lgt** | **Sen Lgt** | **USL** | **DGen** | **ST** | **AUR** | **AUGe** | **AUGd** | **AR** | **AGSe** | **AGSd** |
| | **Distribution Plant** | | | | | | | | | | | | | | | | | | | |
| 1860 | Meters | $694,202,434 | $106,031,524 | $236,683,303 | $187,535,687 | $69,296,185 | $18,500,659 | $21,423,768 | $5,355,435 | $0 | $0 | $0 | $14,773,631 | $7,685,668 | $7,153,485 | $1,572,666 | $428,474 | $13,815,900 | $3,059,495 | $886,553 |
| | **Accumulated Amortization** | | | | | | | | | | | | | | | | | | | |
| | Accum. Amortization of Electric Utility Plant -  Meters only | ($305,853,321) | ($46,715,615) | ($104,278,479) | ($82,624,909) | ($30,530,674) | ($8,151,063) | ($9,438,934) | ($2,359,510) | $0 | $0 | $0 | ($6,509,001) | ($3,386,170) | ($3,151,699) | ($692,889) | ($188,778) | ($6,087,041) | ($1,347,959) | ($390,600) |
| | **Meter Net Fixed Assets** | **$388,349,114** | **$59,315,909** | **$132,404,824** | **$104,910,779** | **$38,765,511** | **$10,349,595** | **$11,984,835** | **$2,995,925** | **$0** | **$0** | **$0** | **$8,264,630** | **$4,299,499** | **$4,001,786** | **$879,777** | **$239,696** | **$7,728,858** | **$1,711,535** | **$495,954** |
| | **Misc Revenue** | | | | | | | | | | | | | | | | | | | |
| 4082 | Retail Services Revenues | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 4084 | Service Transaction Requests (STR) Revenues | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 4090 | Electric Services Incidental to Energy Sales | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 4220 | Other Electric Revenues | ($175,000) | ($7,121) | ($29,903) | ($57,753) | ($22,112) | ($40,942) | ($3,879) | ($7,042) | ($1,176) | ($763) | ($452) | ($30) | $0 | ($428) | ($193) | ($186) | ($1,592) | ($655) | ($774) |
| 4225 | Late Payment Charges | ($10,962,172) | ($1,337,787) | ($3,575,627) | ($2,995,413) | ($1,032,677) | ($670,817) | ($202,350) | ($161,863) | ($21,981) | ($15,001) | ($9,229) | ($31,048) | ($516,365) | ($76,901) | ($9,633) | ($26,535) | ($191,210) | ($38,748) | ($48,989) |
| | Sub-total | ($11,137,172) | ($1,344,908) | ($3,605,529) | ($3,053,165) | ($1,054,788) | ($711,759) | ($206,229) | ($168,905) | ($23,157) | ($15,764) | ($9,681) | ($31,078) | ($516,365) | ($77,329) | ($9,826) | ($26,721) | ($192,803) | ($39,403) | ($49,764) |
| | **Operation** | | | | | | | | | | | | | | | | | | | |
| 5065 | Meter Expense | $11,898,370 | $1,817,341 | $4,056,663 | $3,214,291 | $1,187,711 | $317,094 | $367,195 | $91,790 | $0 | $0 | $0 | $253,214 | $131,729 | $122,608 | $26,955 | $7,344 | $236,799 | $52,439 | $15,195 |
| 5070 | Customer Premises - Operation Labour | $23,458,256 | $4,067,983 | $8,990,298 | $6,872,994 | $1,467,545 | $88,299 | $304,632 | $28,807 | $341,343 | $160,393 | $95,072 | $24,615 | $15,040 | $255,781 | $22,809 | $3,426 | $644,417 | $69,793 | $5,010 |
| 5075 | Customer Premises - Materials and Expenses | $3,774,477 | $654,546 | $1,446,556 | $1,105,878 | $236,131 | $14,207 | $49,016 | $4,635 | $54,923 | $25,808 | $15,297 | $3,961 | $2,420 | $41,156 | $3,670 | $551 | $103,688 | $11,230 | $806 |
| | Sub-total | $39,131,103 | $6,539,870 | $14,493,517 | $11,193,163 | $2,891,386 | $419,601 | $720,844 | $125,232 | $396,265 | $186,201 | $110,370 | $281,790 | $149,189 | $419,544 | $53,434 | $11,321 | $984,904 | $133,461 | $21,012 |
| | **Maintenance** | | | | | | | | | | | | | | | | | | | |
| 5175 | Maintenance of Meters | $7,731,268 | $1,207,140 | $2,694,575 | $2,135,043 | $788,918 | $210,625 | $243,904 | $60,970 | $0 | $0 | $0 | $168,194 | $87,499 | $28,689 | $5,614 | $820 | $81,846 | $14,448 | $2,983 |
| | **Billing and Collection** | | | | | | | | | | | | | | | | | | | |
| 5310 | Meter Reading Expense | $11,569,881 | $85,618 | $786,859 | $7,892,866 | $1,919,063 | $524,038 | $144,112 | $87,890 | $0 | $0 | $0 | $0 | $0 | $2,648 | $8,358 | $5,451 | $13,108 | $20,830 | $79,039 |
| 5315 | Customer Billing | $50,216,941 | $9,377,646 | $19,117,640 | $13,854,149 | $3,413,943 | $410,972 | $708,665 | $134,075 | $200,818 | $353,178 | $207,621 | $54,038 | $53,047 | $590,003 | $53,061 | $15,946 | $1,486,460 | $162,358 | $23,320 |
| 5320 | Collecting | $3,441,251 | $642,628 | $1,310,088 | $949,393 | $233,950 | $28,163 | $48,563 | $9,188 | $13,762 | $24,202 | $14,228 | $3,703 | $3,635 | $40,432 | $3,636 | $1,093 | $101,864 | $11,126 | $1,598 |
| 5325 | Collecting- Cash Over and Short | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 5330 | Collection Charges | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | Sub-total | $65,228,072 | $10,105,893 | $21,214,587 | $22,696,408 | $5,566,955 | $963,173 | $901,341 | $231,153 | $214,580 | $377,381 | $221,848 | $57,741 | $56,682 | $633,082 | $65,056 | $22,490 | $1,601,432 | $194,315 | $103,957 |
| | Total Operation, Maintenance and Billing | $112,090,444 | $17,852,902 | $38,402,678 | $36,024,614 | $9,247,259 | $1,593,399 | $1,866,088 | $417,355 | $610,845 | $563,581 | $332,218 | $507,725 | $293,370 | $1,081,315 | $124,104 | $34,631 | $2,668,182 | $342,224 | $127,952 |
| | **Amortization Expense - Meters** | $48,046,754 | $7,338,595 | $16,381,193 | $12,979,616 | $4,796,089 | $1,280,457 | $1,482,770 | $370,657 | $0 | $0 | $0 | $1,022,504 | $531,936 | $495,103 | $108,847 | $29,655 | $956,218 | $211,752 | $61,360 |
| | **Allocated PILs** | $1,743,524 | $271,997 | $607,022 | $480,921 | $177,757 | $47,456 | $54,967 | $13,738 | $0 | $0 | $0 | $37,998 | $19,716 | $6,949 | $1,366 | $223 | $19,228 | $3,447 | $740 |
| | **Allocated Debt Return** | $9,703,661 | $1,513,814 | $3,378,410 | $2,676,586 | $989,312 | $264,116 | $305,923 | $76,459 | $0 | $0 | $0 | $211,477 | $109,728 | $38,676 | $7,604 | $1,238 | $107,016 | $19,185 | $4,116 |
| | **Allocated Equity Return** | $13,826,842 | $2,157,048 | $4,813,929 | $3,813,893 | $1,409,680 | $376,342 | $435,913 | $108,947 | $0 | $0 | $0 | $301,335 | $156,353 | $55,110 | $10,835 | $1,765 | $152,489 | $27,337 | $5,865 |
| | **Total** | **$174,274,053** | **$27,789,449** | **$59,977,704** | **$52,922,464** | **$15,565,309** | **$2,850,011** | **$3,939,433** | **$818,251** | **$587,688** | **$547,818** | **$322,537** | **$2,049,961** | **$594,738** | **$1,599,824** | **$242,930** | **$40,791** | **$3,710,332** | **$564,542** | **$150,269** |

## Scenario 2

***Accounts included in Directly Related Customer Costs Plus General Administration  Allocation***

| | | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **USoA Account #** | **Accounts** | **Total** | **UR** | **R1** | **R2** | **GSe** | **GSd** | **UGe** | **UGd** | **St Lgt** | **Sen Lgt** | **USL** | **DGen** | **ST** | **AUR** | **AUGe** | **AUGd** | **AR** | **AGSe** | **AGSd** |
| | **Distribution Plant** | | | | | | | | | | | | | | | | | | | |
| 1860 | Meters | $694,202,434 | $106,031,524 | $236,683,303 | $187,535,687 | $69,296,185 | $18,500,659 | $21,423,768 | $5,355,435 | $0 | $0 | $0 | $14,773,631 | $7,685,668 | $7,153,485 | $1,572,666 | $428,474 | $13,815,900 | $3,059,495 | $886,553 |
| | **Accumulated Amortization** | | | | | | | | | | | | | | | | | | | |
| | Accum. Amortization of Electric Utility Plant -  Meters only | ($305,853,321) | ($46,715,615) | ($104,278,479) | ($82,624,909) | ($30,530,674) | ($8,151,063) | ($9,438,934) | ($2,359,510) | $0 | $0 | $0 | ($6,509,001) | ($3,386,170) | ($3,151,699) | ($692,889) | ($188,778) | ($6,087,041) | ($1,347,959) | ($390,600) |
| | **Meter Net Fixed Assets** | $388,349,114 | $59,315,909 | $132,404,824 | $104,910,779 | $38,765,511 | $10,349,595 | $11,984,835 | $2,995,925 | $0 | $0 | $0 | $8,264,630 | $4,299,499 | $4,001,786 | $879,777 | $239,696 | $7,728,858 | $1,711,535 | $495,954 |
| | **Allocated General Plant Net Fixed Assets** | $20,106,446 | $3,131,034 | $7,018,857 | $5,573,456 | $2,047,536 | $547,056 | $630,319 | $158,176 | $0 | $0 | $0 | $413,481 | $226,959 | $77,721 | $15,208 | $2,458 | $217,354 | $38,605 | $8,226 |
| | **Meter Net Fixed Assets Including General Plant** | $408,455,560 | $62,446,943 | $139,423,681 | $110,484,235 | $40,813,047 | $10,896,651 | $12,615,154 | $3,154,101 | $0 | $0 | $0 | $8,678,111 | $4,526,457 | $4,079,507 | $894,986 | $242,154 | $7,946,213 | $1,750,141 | $504,179 |
| | **Misc Revenue** | | | | | | | | | | | | | | | | | | | |
| 4082 | Retail Services Revenues | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 4084 | Service Transaction Requests (STR) Revenues | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 4090 | Electric Services Incidental to Energy Sales | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 4220 | Other Electric Revenues | ($175,000) | ($7,121) | ($29,903) | ($57,753) | ($22,112) | ($40,942) | ($3,879) | ($7,042) | ($1,176) | ($763) | ($452) | ($30) | $0 | ($428) | ($193) | ($186) | ($1,592) | ($655) | ($774) |
| 4225 | Late Payment Charges | ($10,962,172) | ($1,337,787) | ($3,575,627) | ($2,995,413) | ($1,032,677) | ($670,817) | ($202,350) | ($161,863) | ($21,981) | ($15,001) | ($9,229) | ($31,048) | ($516,365) | ($76,901) | ($9,633) | ($26,535) | ($191,210) | ($38,748) | ($48,989) |
| | *Sub-total* | ($11,137,172) | ($1,344,908) | ($3,605,529) | ($3,053,165) | ($1,054,788) | ($711,759) | ($206,229) | ($168,905) | ($23,157) | ($15,764) | ($9,681) | ($31,078) | ($516,365) | ($77,329) | ($9,826) | ($26,721) | ($192,803) | ($39,403) | ($49,764) |
| | **Operation** | | | | | | | | | | | | | | | | | | | |
| 5065 | Meter Expense | $11,898,370 | $1,817,341 | $4,056,663 | $3,214,291 | $1,187,711 | $317,094 | $367,195 | $91,790 | $0 | $0 | $0 | $253,214 | $131,729 | $122,608 | $26,955 | $7,344 | $236,799 | $52,439 | $15,195 |
| 5070 | Customer Premises - Operation Labour | $23,458,256 | $4,067,983 | $8,990,298 | $6,872,994 | $1,467,545 | $88,299 | $304,632 | $28,807 | $341,343 | $160,393 | $95,072 | $24,615 | $15,040 | $255,781 | $22,809 | $3,426 | $644,417 | $69,793 | $5,010 |
| 5075 | Customer Premises - Materials and Expenses | $3,774,477 | $654,546 | $1,446,556 | $1,105,878 | $236,131 | $14,207 | $49,016 | $4,635 | $54,923 | $25,808 | $15,297 | $3,961 | $2,420 | $41,156 | $3,670 | $551 | $103,688 | $11,230 | $806 |
| | *Sub-total* | $39,131,103 | $6,539,870 | $14,493,517 | $11,193,163 | $2,891,386 | $419,601 | $720,844 | $125,232 | $396,265 | $186,201 | $110,370 | $281,790 | $149,189 | $419,544 | $53,434 | $11,321 | $984,904 | $133,461 | $21,012 |
| | **Maintenance** | | | | | | | | | | | | | | | | | | | |
| 5175 | Maintenance of Meters | $7,731,268 | $1,207,140 | $2,694,575 | $2,135,043 | $788,918 | $210,625 | $243,904 | $60,970 | $0 | $0 | $0 | $168,194 | $87,499 | $28,689 | $5,614 | $820 | $81,846 | $14,448 | $2,983 |
| | **Billing and Collection** | | | | | | | | | | | | | | | | | | | |
| 5310 | Meter Reading Expense | $11,569,881 | $85,618 | $786,859 | $7,892,866 | $1,919,063 | $524,038 | $144,112 | $87,890 | $0 | $0 | $0 | $0 | $0 | $2,648 | $8,358 | $5,451 | $13,108 | $20,830 | $79,039 |
| 5315 | Customer Billing | $50,216,941 | $9,377,646 | $19,117,640 | $13,854,149 | $3,413,943 | $410,972 | $708,665 | $134,075 | $200,818 | $353,178 | $207,621 | $54,038 | $53,047 | $590,003 | $53,061 | $15,946 | $1,486,460 | $162,358 | $23,320 |
| 5320 | Collecting | $3,441,251 | $642,628 | $1,310,088 | $949,393 | $233,950 | $28,163 | $48,563 | $9,188 | $13,762 | $24,202 | $14,228 | $3,703 | $3,635 | $40,432 | $3,636 | $1,093 | $101,864 | $11,126 | $1,598 |
| 5325 | Collecting- Cash Over and Short | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 5330 | Collection Charges | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | *Sub-total* | $65,228,072 | $10,105,893 | $21,214,587 | $22,696,408 | $5,566,955 | $963,173 | $901,341 | $231,153 | $214,580 | $377,381 | $221,848 | $57,741 | $56,682 | $633,082 | $65,056 | $22,490 | $1,601,432 | $194,315 | $103,957 |
| | Total Operation, Maintenance and Billing | $112,090,444 | $17,852,902 | $38,402,678 | $36,024,614 | $9,247,259 | $1,593,399 | $1,866,088 | $417,355 | $610,845 | $563,581 | $332,218 | $507,725 | $293,370 | $1,081,315 | $124,104 | $34,631 | $2,668,182 | $342,224 | $127,952 |
| | **Amortization Expense - Meters** | $48,046,754 | $7,338,595 | $16,381,193 | $12,979,616 | $4,796,089 | $1,280,457 | $1,482,770 | $370,657 | $0 | $0 | $0 | $1,022,504 | $531,936 | $495,103 | $108,847 | $29,655 | $956,218 | $211,752 | $61,360 |
| | ***Amortization Expense - General Plant assigned to Meters*** | $5,213,879 | $811,920 | $1,820,087 | $1,445,274 | $530,954 | $141,859 | $163,450 | $41,017 | $0 | $0 | $0 | $107,221 | $58,853 | $20,154 | $3,944 | $637 | $56,363 | $10,011 | $2,133 |
| | **Admin and General** | $46,345,759 | $7,218,530 | $15,716,994 | $14,996,279 | $3,901,247 | $713,208 | $787,440 | $186,624 | $252,375 | $228,362 | $135,446 | $286,006 | $130,931 | $435,846 | $51,794 | $16,420 | $1,087,187 | $143,735 | $57,335 |
| | **Allocated PILs** | $1,834,857 | $286,355 | $639,201 | $506,470 | $187,145 | $49,964 | $57,858 | $14,463 | $0 | $0 | $0 | $39,899 | $20,756 | $7,084 | $1,390 | $225 | $19,769 | $3,525 | $752 |
| | **Allocated Debt Return** | $10,211,975 | $1,593,722 | $3,557,501 | $2,818,781 | $1,041,566 | $278,077 | $322,013 | $80,496 | $0 | $0 | $0 | $222,057 | $115,521 | $39,427 | $7,736 | $1,251 | $110,026 | $19,618 | $4,184 |
| | **Allocated Equity Return** | $14,551,143 | $2,270,909 | $5,069,118 | $4,016,509 | $1,484,138 | $396,234 | $458,839 | $114,699 | $0 | $0 | $0 | $316,411 | $164,606 | $56,180 | $11,022 | $1,783 | $156,777 | $27,954 | $5,962 |
| | **Total** | **$227,157,639** | **$36,028,026** | **$77,981,244** | **$69,734,378** | **$20,133,611** | **$3,741,439** | **$4,932,230** | **$1,056,407** | **$840,063** | **$776,180** | **$457,983** | **$2,470,746** | **$799,609** | **$2,057,781** | **$299,011** | **$57,881** | **$4,861,720** | **$719,415** | **$209,915** |

## Scenario 3

***Minimum System Customer Costs Adjusted for PLCC - High Limit Fixed Customer Charge***

| USoA Account # | Accounts | Total | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | UR | R1 | R2 | GSe | GSd | UGe | UGd | St Lgt | Sen Lgt | USL | DGen | ST | AUR | AUGe | AUGd | AR | AGSe | AGSd |
| | **Distribution Plant** | | | | | | | | | | | | | | | | | | | |
| 1565 | Conservation and Demand Management Expenditures and Recoveries | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 1830 | Poles, Towers and Fixtures | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 1830-3 | Poles, Towers and Fixtures - Subtransmission Bulk Delivery | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 1830-4 | Poles, Towers and Fixtures - Primary | $810,844,023 | $51,994,900 | $218,327,921 | $421,666,224 | $56,629,785 | $3,540,707 | $4,897,997 | $525,054 | $8,585,127 | $5,568,655 | $3,300,789 | $430,670 | $614,533 | $8,880,381 | $791,914 | $118,951 | $22,373,347 | $2,423,113 | $173,957 |
| 1830-5 | Poles, Towers and Fixtures - Secondary | $601,280,870 | $38,658,719 | $162,328,955 | $313,512,982 | $42,104,802 | $0 | $3,641,709 | $0 | $8,811,326 | $4,140,350 | $2,454,169 | $0 | $0 | $6,602,650 | $588,796 | $0 | $16,634,803 | $1,801,608 | $0 |
| 1835 | Overhead Conductors and Devices | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 1835-3 | Overhead Conductors and Devices - Subtransmission Bulk Delivery | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 1835-4 | Overhead Conductors and Devices - Primary | $728,033,150 | $46,684,701 | $196,030,259 | $378,601,779 | $50,846,229 | $3,179,097 | $4,397,768 | $471,430 | $7,708,334 | $4,999,933 | $2,963,682 | $386,686 | $551,771 | $7,973,434 | $711,037 | $106,802 | $20,088,374 | $2,175,642 | $156,191 |
| 1835-5 | Overhead Conductors and Devices - Secondary | $105,301,448 | $6,770,246 | $28,428,435 | $54,905,075 | $7,373,753 | $0 | $637,767 | $0 | $1,543,115 | $725,093 | $429,795 | $0 | $0 | $1,156,313 | $103,115 | $0 | $2,913,229 | $315,513 | $0 |
| 1840 | Underground Conduit | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 1840-3 | Underground Conduit - Bulk Delivery | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 1840-4 | Underground Conduit - Primary | $14,533,814 | $932,679 | $3,916,344 | $7,563,806 | $1,015,819 | $63,513 | $87,860 | $9,418 | $153,999 | $99,890 | $59,209 | $7,725 | $0 | $159,295 | $14,205 | $2,134 | $401,331 | $43,466 | $3,120 |
| 1840-5 | Underground Conduit - Secondary | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 1845 | Underground Conductors and Devices | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 1845-3 | Underground Conductors and Devices - Bulk Delivery | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 1845-4 | Underground Conductors and Devices - Primary | $229,060,350 | $14,699,502 | $61,723,586 | $119,209,451 | $16,009,832 | $1,000,995 | $1,384,715 | $148,438 | $2,427,105 | $1,574,317 | $933,168 | $121,755 | $0 | $2,510,577 | $223,882 | $33,629 | $6,325,179 | $685,039 | $49,180 |
| 1845-5 | Underground Conductors and Devices - Secondary | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 1850 | Line Transformers | $1,697,882,714 | $109,049,530 | $457,901,781 | $884,365,657 | $118,770,331 | $6,716,014 | $10,272,627 | $956,959 | $18,005,690 | $11,679,208 | $6,922,785 | $457,694 | $0 | $18,624,930 | $1,660,891 | $194,412 | $46,923,891 | $5,082,024 | $298,292 |
| 1855 | Services | $857,967,029 | $88,595,292 | $293,695,191 | $449,054,167 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $5,570,561 | $0 | $0 | $21,051,817 | $0 | $0 |
| 1860 | Meters | $694,202,434 | $106,031,524 | $236,683,303 | $187,535,687 | $69,296,185 | $18,500,659 | $21,423,768 | $5,355,435 | $0 | $0 | $0 | $14,773,631 | $7,685,668 | $7,153,485 | $1,572,666 | $428,474 | $13,815,900 | $3,059,495 | $886,553 |
| 9999 | blank row | | | | | | | | | | | | | | | | | | | |
| | *Sub-total* | $5,739,105,833 | $463,417,093 | $1,659,035,775 | $2,816,414,828 | $362,046,735 | $33,000,985 | $46,744,210 | $7,466,735 | $47,234,696 | $28,787,447 | $17,063,597 | $16,178,160 | $8,851,973 | $58,631,627 | $5,666,507 | $884,401 | $150,527,871 | $15,585,899 | $1,567,294 |
| | **Accumulated Amortization** | | | | | | | | | | | | | | | | | | | |
| | Accum. Amortization of Electric Utility Plant -Line Transformers, Services and Meters | ($2,518,077,796) | ($210,368,823) | ($736,615,357) | ($1,221,444,594) | ($148,665,999) | ($18,048,102) | ($20,355,929) | ($4,853,791) | ($18,446,136) | ($11,271,954) | ($6,729,704) | ($7,128,318) | ($13,937,022) | ($24,760,992) | ($2,369,214) | ($588,543) | ($64,944,156) | ($6,462,525) | ($1,086,638) |
| | **Customer Related Net Fixed Assets** | $3,221,028,038 | $253,048,270 | $922,420,418 | $1,594,970,234 | $213,380,737 | $14,952,883 | $26,388,281 | $2,612,945 | $28,788,560 | $17,515,493 | $10,333,893 | $9,049,842 | ($5,085,049) | $33,870,635 | $3,297,293 | $295,858 | $85,583,715 | $9,123,374 | $480,656 |
| | **Allocated General Plant Net Fixed Assets** | $172,019,990 | $13,357,339 | $48,898,045 | $84,733,868 | $11,270,451 | $790,375 | $1,387,840 | $137,956 | $1,530,302 | $5,840,238 | $550,800 | $452,765 | ($268,426) | $657,821 | $56,998 | $3,034 | $2,406,823 | $205,787 | $7,972 |
| | **Customer Related NFA Including General Plant** | $3,393,048,028 | $266,405,609 | $971,318,463 | $1,679,704,102 | $224,651,187 | $15,743,258 | $27,776,121 | $2,750,900 | $30,318,862 | $23,355,731 | $10,884,693 | $9,502,607 | ($5,353,474) | $34,528,456 | $3,354,291 | $298,892 | $87,990,539 | $9,329,161 | $488,628 |
| | **Misc Revenue** | | | | | | | | | | | | | | | | | | | |
| 4082 | Retail Services Revenues | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 4084 | Service Transaction Requests (STR) Revenues | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 4090 | Electric Services Incidental to Energy Sales | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 4220 | Other Electric Revenues | ($175,000) | ($7,121) | ($29,903) | ($57,753) | ($22,112) | ($40,942) | ($3,879) | ($7,042) | ($1,176) | ($763) | ($452) | ($30) | $0 | ($428) | ($193) | ($186) | ($1,592) | ($655) | ($774) |
| 4225 | Late Payment Charges | ($10,962,172) | ($1,337,787) | ($3,575,627) | ($2,995,413) | ($1,032,677) | ($670,817) | ($202,350) | ($161,863) | ($21,981) | ($15,001) | ($9,229) | ($31,048) | ($516,365) | ($76,901) | ($9,633) | ($26,535) | ($191,210) | ($38,748) | ($48,989) |
| 4235 | Miscellaneous Service Revenues | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 4235-1 | Account Set Up Charges | ($1,383,530) | ($258,364) | ($526,711) | ($381,697) | ($94,058) | ($11,323) | ($19,524) | ($3,694) | ($5,533) | ($9,730) | ($5,720) | ($1,489) | ($1,461) | ($16,255) | ($1,462) | ($439) | ($40,954) | ($4,473) | ($643) |
| 4235-2 | Sentinel Lights Pole Rental Charges | ($2,594,946) | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | ($2,594,946) | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 4235-90 | Miscellaneous Service Revenues - Residual | ($13,275,745) | ($1,122,541) | ($3,432,737) | ($5,512,857) | ($1,205,756) | ($759,376) | ($169,719) | ($143,428) | ($86,128) | ($47,412) | ($29,809) | ($22,178) | ($404,364) | ($66,855) | ($9,768) | ($7,442) | ($202,068) | ($31,652) | ($21,656) |
| | Sub-total | ($28,391,394) | ($2,725,813) | ($7,564,978) | ($8,947,719) | ($2,354,602) | ($1,482,458) | ($395,472) | ($316,027) | ($114,818) | ($2,667,852) | ($45,210) | ($54,744) | ($922,191) | ($160,439) | ($21,055) | ($34,602) | ($435,824) | ($75,528) | ($72,062) |
| | **Operating and Maintenance** | | | | | | | | | | | | | | | | | | | |
| 5005 | Operation Supervision and Engineering | $1,522,356 | $110,608 | $436,473 | $800,993 | $91,199 | $7,213 | $8,374 | $1,783 | $14,405 | $8,728 | $5,207 | $464 | $7,407 | $5,536 | $405 | $48 | $21,731 | $1,634 | $147 |
| 5010 | Load Dispatching | $580,960 | $42,210 | $166,566 | $305,674 | $34,803 | $2,752 | $3,196 | $680 | $5,497 | $3,331 | $1,987 | $177 | $2,827 | $2,113 | $154 | $18 | $8,293 | $623 | $56 |
| 5020 | Overhead Distribution Lines and Feeders - Operation Labour | $4,754,409 | $312,304 | $1,311,371 | $2,532,708 | $340,143 | $14,563 | $29,419 | $2,160 | $57,750 | $33,448 | $19,826 | $1,771 | $2,528 | $18,767 | $1,490 | $82 | $69,840 | $6,030 | $211 |
| 5025 | Overhead Distribution Lines & Feeders - Operation Supplies and Expenses | $231,168 | $15,185 | $63,761 | $123,145 | $16,538 | $708 | $1,430 | $105 | $2,808 | $1,626 | $964 | $86 | $123 | $912 | $72 | $4 | $3,396 | $293 | $10 |
| 5035 | Overhead Distribution Transformers- Operation | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 5040 | Underground Distribution Lines and Feeders - Operation Labour | $821,931 | $53,991 | $226,710 | $437,855 | $58,804 | $3,677 | $5,086 | $545 | $8,915 | $5,782 | $3,428 | $447 | $0 | $3,244 | $257 | $21 | $12,073 | $1,042 | $53 |
| 5045 | Underground Distribution Lines & Feeders - Operation Supplies & Expenses | $77,056 | $5,062 | $21,254 | $41,049 | $5,513 | $345 | $477 | $51 | $836 | $542 | $321 | $42 | $0 | $304 | $24 | $2 | $1,132 | $98 | $5 |
| 5055 | Underground Distribution Transformers - Operation | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 5065 | Meter Expense | $11,898,370 | $1,817,341 | $4,056,663 | $3,214,291 | $1,187,711 | $317,094 | $367,195 | $91,790 | $0 | $0 | $0 | $253,214 | $131,729 | $122,608 | $26,955 | $7,344 | $236,799 | $52,439 | $15,195 |
| 5070 | Customer Premises - Operation Labour | $23,458,256 | $4,067,983 | $8,990,298 | $6,872,994 | $1,467,545 | $88,299 | $304,632 | $28,807 | $341,343 | $160,393 | $95,072 | $24,615 | $15,040 | $255,781 | $22,809 | $3,426 | $644,417 | $69,793 | $5,010 |
| 5075 | Customer Premises - Materials and Expenses | $3,774,477 | $654,546 | $1,446,556 | $1,105,878 | $236,131 | $14,207 | $49,016 | $4,635 | $54,923 | $25,808 | $15,297 | $3,961 | $2,420 | $41,156 | $3,670 | $551 | $103,688 | $11,230 | $806 |
| 5085 | Miscellaneous Distribution Expense | $16,380,615 | $1,190,145 | $4,696,467 | $8,618,719 | $981,306 | $77,607 | $90,109 | $19,185 | $155,001 | $93,915 | $56,029 | $4,996 | $79,700 | $59,566 | $4,354 | $521 | $233,830 | $17,579 | $1,586 |
| 5090 | Underground Distribution Lines and Feeders - Rental Paid | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 5095 | Overhead Distribution Lines and Feeders - Rental Paid | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 5096 | Other Rent | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 5105 | Maintenance Supervision and Engineering | $5,988,606 | $435,107 | $1,716,986 | $3,150,927 | $358,757 | $28,372 | $32,943 | $7,014 | $56,667 | $34,335 | $20,484 | $1,826 | $29,138 | $21,777 | $1,592 | $190 | $85,486 | $6,427 | $580 |
| 5120 | Maintenance of Poles, Towers and Fixtures | $9,631,000 | $632,803 | $2,657,157 | $5,131,882 | $689,212 | $24,716 | $59,611 | $3,665 | $121,435 | $67,773 | $40,172 | $3,006 | $4,290 | $38,027 | $3,018 | $139 | $141,517 | $12,218 | $358 |
| 5125 | Maintenance of Overhead Conductors and Devices | $17,978,823 | $1,180,440 | $4,956,697 | $9,573,085 | $1,285,666 | $70,204 | $111,199 | $10,411 | $204,299 | $126,425 | $74,938 | $8,539 | $12,185 | $70,931 | $5,630 | $396 | $263,970 | $22,790 | $1,018 |
| 5130 | Maintenance of Overhead Services | $8,157,004 | $855,903 | $2,837,335 | $4,338,230 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $19,072 | $0 | $0 | $106,464 | $0 | $0 |
| 5135 | Overhead Distribution Lines and Feeders - Right of Way | $69,401,515 | $4,558,788 | $19,142,470 | $36,970,686 | $4,965,164 | $212,578 | $429,445 | $31,523 | $842,989 | $488,246 | $289,405 | $25,857 | $36,896 | $273,944 | $21,743 | $1,199 | $1,019,480 | $88,019 | $3,083 |
| 5145 | Maintenance of Underground Conduit | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 5150 | Maintenance of Underground Conductors and Devices | $694,161 | $45,598 | $191,468 | $369,790 | $49,663 | $3,105 | $4,295 | $460 | $7,529 | $4,884 | $2,895 | $378 | $0 | $2,740 | $217 | $18 | $10,196 | $880 | $45 |
| 5155 | Maintenance of Underground Services | $6,933,454 | $727,517 | $2,411,735 | $3,687,495 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $16,211 | $0 | $0 | $90,495 | $0 | $0 |
| 5160 | Maintenance of Line Transformers | $1,882,147 | $123,734 | $519,561 | $1,003,450 | $134,763 | $7,620 | $11,656 | $1,086 | $20,430 | $13,252 | $7,855 | $519 | $0 | $7,435 | $590 | $37 | $27,669 | $2,389 | $100 |
| 5175 | Maintenance of Meters | $7,731,268 | $1,207,140 | $2,694,575 | $2,135,043 | $788,918 | $210,625 | $243,904 | $60,970 | $0 | $0 | $0 | $168,194 | $87,499 | $28,689 | $5,614 | $820 | $81,846 | $14,448 | $2,983 |
| | *Sub-total* | $191,897,575 | $18,036,404 | $58,544,103 | $90,413,894 | $12,691,835 | $1,083,686 | $1,751,988 | $264,870 | $1,894,825 | $1,068,489 | $633,881 | $498,093 | $411,780 | $988,812 | $98,595 | $14,816 | $3,162,323 | $307,932 | $31,249 |
| | **Billing and Collection** | | | | | | | | | | | | | | | | | | | |
| 5305 | Supervision | $67,338 | $12,575 | $25,635 | $18,577 | $4,578 | $551 | $950 | $180 | $269 | $474 | $278 | $72 | $71 | $791 | $71 | $21 | $1,993 | $218 | $31 |
| 5310 | Meter Reading Expense | $11,569,881 | $85,618 | $786,859 | $7,892,866 | $1,919,063 | $524,038 | $144,112 | $87,890 | $0 | $0 | $0 | $0 | $0 | $2,648 | $8,358 | $5,451 | $13,108 | $20,830 | $79,039 |
| 5315 | Customer Billing | $50,216,941 | $9,377,646 | $19,117,640 | $13,854,149 | $3,413,943 | $410,972 | $708,665 | $134,075 | $200,818 | $353,178 | $207,621 | $54,038 | $53,047 | $590,003 | $53,061 | $15,946 | $1,486,460 | $162,358 | $23,320 |
| 5320 | Collecting | $3,441,251 | $642,628 | $1,310,088 | $949,393 | $233,950 | $28,163 | $48,563 | $9,188 | $13,762 | $24,202 | $14,228 | $3,703 | $3,635 | $40,432 | $3,636 | $1,093 | $101,864 | $11,126 | $1,598 |
| 5325 | Collecting- Cash Over and Short | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 5330 | Collection Charges | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 5335 | Bad Debt Expense | $18,059,732 | $2,195,768 | $7,173,427 | $4,720,004 | $1,339,894 | $1,469,994 | $221,676 | $264,073 | $19,121 | $24,887 | $4,913 | $2,896 | $116,098 | $149,781 | $16,349 | $27,643 | $262,930 | $35,049 | $15,229 |
| 5340 | Miscellaneous Customer Accounts Expenses | $6,528,362 | $1,219,124 | $2,485,354 | $1,801,083 | $443,823 | $53,428 | $92,129 | $17,430 | $26,107 | $45,914 | $26,991 | $7,025 | $6,896 | $76,702 | $6,898 | $2,073 | $193,245 | $21,107 | $3,032 |
| | *Sub-total* | $89,883,504 | $13,533,360 | $30,899,004 | $29,236,072 | $7,355,250 | $2,487,145 | $1,216,096 | $512,836 | $260,077 | $448,655 | $254,031 | $67,735 | $179,747 | $860,356 | $88,374 | $52,228 | $2,059,600 | $250,688 | $122,249 |
| | *Sub Total Operating, Maintenance and Biling* | *$281,781,079* | *$31,569,764* | *$89,443,107* | *$119,649,967* | *$20,047,086* | *$3,570,831* | *$2,968,084* | *$777,706* | *$2,154,902* | *$1,517,144* | *$887,912* | *$565,828* | *$591,527* | *$1,849,169* | *$186,969* | *$67,044* | *$5,221,923* | *$558,620* | *$153,498* |
| | **Amortization Expense - Customer Related** | $167,330,506 | $15,781,630 | $49,748,873 | $74,296,815 | $11,859,010 | $1,861,941 | $2,134,467 | $516,673 | $1,105,968 | $674,403 | $402,569 | $1,057,886 | $1,147,740 | $1,703,267 | $209,034 | $53,010 | $4,157,707 | $517,450 | $102,064 |
| | **Amortization Expense - General Plant assigned to Meters** | $43,672,917 | $3,463,743 | $12,679,939 | $21,972,663 | $2,922,584 | $204,955 | $359,886 | $35,774 | $396,828 | $580,211 | $142,830 | $117,408 | ($69,606) | $170,582 | $14,780 | $787 | $624,123 | $53,363 | $2,067 |
| | **Admin and General** | $116,570,788 | $12,764,720 | $36,606,217 | $49,807,731 | $8,457,494 | $1,598,310 | $1,252,453 | $347,759 | $890,312 | $614,745 | $362,003 | $318,736 | $263,999 | $745,346 | $78,031 | $31,788 | $2,127,742 | $234,622 | $68,782 |
| | **Allocated PILs** | $15,213,402 | $1,221,623 | $4,453,101 | $7,699,921 | $1,030,123 | $72,187 | $127,393 | $12,614 | $138,980 | $84,558 | $49,888 | $43,689 | ($24,549) | $59,959 | $5,209 | $277 | $218,909 | $18,789 | $729 |
| | **Allocated Debt Return** | $84,670,851 | $6,798,994 | $24,783,930 | $42,854,245 | $5,733,192 | $401,760 | $709,010 | $70,206 | $773,502 | $470,613 | $277,655 | $243,154 | ($136,627) | $333,705 | $28,992 | $1,544 | $1,218,348 | $104,574 | $4,055 |
| | **Allocated Equity Return** | $120,648,323 | $9,687,953 | $35,314,864 | $61,063,433 | $8,169,281 | $572,471 | $1,010,275 | $100,037 | $1,102,170 | $670,581 | $395,633 | $346,473 | ($194,681) | $475,500 | $41,311 | $2,200 | $1,736,035 | $149,008 | $5,779 |
| | **PLCC Adjustment for Line Transformer** | $25,386,774 | $0 | $0 | $0 | $17,295,138 | $2,487,654 | $3,864,026 | $354,414 | $0 | $0 | $0 | $0 | $0 | $0 | $331,389 | $32,543 | $0 | $963,055 | $58,554 |
| | **PLCC Adjustment for Primary Costs** | $114,513,741 | $7,404,258 | $31,135,340 | $60,192,442 | $9,586,924 | $589,636 | $828,694 | $87,424 | $1,381,223 | $0 | $0 | $71,189 | $1,713 | $703,206 | $58,804 | $6,788 | $2,242,555 | $210,902 | $12,643 |
| | **PLCC Adjustment for Secondary Costs** | $73,777,131 | $4,828,189 | $20,313,660 | $38,709,309 | $6,037,230 | $0 | $519,948 | $0 | $1,280,989 | $0 | $0 | $0 | $0 | $463,645 | $36,514 | $0 | $1,456,228 | $131,419 | $0 |
| | **Total** | **$587,818,826** | **$66,330,166** | **$194,016,053** | **$269,495,304** | **$22,944,874** | **$3,722,708** | **$2,953,429** | **$1,102,903** | **$3,785,632** | **$1,944,402** | **$2,473,280** | **$2,567,241** | **$653,900** | **$4,010,238** | **$116,563** | **$82,717** | **$11,170,180** | **$255,522** | **$193,714** |

**Below: Grouping to avoid disclosure**

## Scenario 1

***Accounts included in Avoided Costs Plus General Administration Allocation***

| Accounts | Total | UR | R1 | R2 | GSe | GSd | UGe | UGd | St Lgt | Sen Lgt | USL | DGen | ST | AUR | AUGe | AUGd | AR | AGSe | AGSd |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Distribution Plant** | | | | | | | | | | | | | | | | | | | |
| CWMC | $ 694,202,434 | $ 106,031,524 | $ 236,683,303 | $ 187,535,687 | $ 69,296,185 | $ 18,500,659 | $ 21,423,768 | $ 5,355,435 | $ - | $ - | $ - | $ 14,773,631 | $ 7,685,668 | $ 7,153,485 | $ 1,572,666 | $ 428,474 | $ 13,815,900 | $ 3,059,495 | $ 886,553 |
| **Accumulated Amortization** | | | | | | | | | | | | | | | | | | | |
| Accum. Amortization of Electric Utility Plant - Meters only | $ (305,853,321) | $ (46,715,615) | $ (104,278,479) | $ (82,624,909) | $ (30,530,674) | $ (8,151,063) | $ (9,438,934) | $ (2,359,510) | $ - | $ - | $ - | $ (6,509,001) | $ (3,386,170) | $ (3,151,699) | $ (692,889) | $ (188,778) | $ (6,087,041) | $ (1,347,959) | $ (390,600) |
| **Meter Net Fixed Assets** | $ 388,349,114 | $ 59,315,909 | $ 132,404,824 | $ 104,910,779 | $ 38,765,511 | $ 10,349,595 | $ 11,984,835 | $ 2,995,925 | $ - | $ - | $ - | $ 8,264,630 | $ 4,299,499 | $ 4,001,786 | $ 879,777 | $ 239,696 | $ 7,728,858 | $ 1,711,535 | $ 495,954 |
| **Misc Revenue** | | | | | | | | | | | | | | | | | | | |
| CWNB | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| NFA | $ (175,000) | $ (7,121) | $ (29,903) | $ (57,753) | $ (22,112) | $ (40,942) | $ (3,879) | $ (7,042) | $ (1,176) | $ (763) | $ (452) | $ (30) | $ - | $ (428) | $ (193) | $ (186) | $ (1,592) | $ (655) | $ (774) |
| LPHA | $ (10,962,172) | $ (1,337,787) | $ (3,575,627) | $ (2,995,413) | $ (1,032,677) | $ (670,817) | $ (202,350) | $ (161,863) | $ (21,981) | $ (15,001) | $ (9,229) | $ (31,048) | $ (516,365) | $ (76,901) | $ (9,633) | $ (26,535) | $ (191,210) | $ (38,748) | $ (48,989) |
| *Sub-total* | $ (11,137,172) | $ (1,344,908) | $ (3,605,529) | $ (3,053,165) | $ (1,054,788) | $ (711,759) | $ (206,229) | $ (168,905) | $ (23,157) | $ (15,764) | $ (9,681) | $ (31,078) | $ (516,365) | $ (77,329) | $ (9,826) | $ (26,721) | $ (192,803) | $ (39,403) | $ (49,764) |
| **Operation** | | | | | | | | | | | | | | | | | | | |
| CWMC | $ 11,898,370 | $ 1,817,341 | $ 4,056,663 | $ 3,214,291 | $ 1,187,711 | $ 317,094 | $ 367,195 | $ 91,790 | $ - | $ - | $ - | $ 253,214 | $ 131,729 | $ 122,608 | $ 26,955 | $ 7,344 | $ 236,799 | $ 52,439 | $ 15,195 |
| CCA | $ 27,232,733 | $ 4,722,529 | $ 10,436,853 | $ 7,978,872 | $ 1,703,675 | $ 102,506 | $ 353,648 | $ 33,442 | $ 396,265 | $ 186,201 | $ 110,370 | $ 28,575 | $ 17,460 | $ 296,936 | $ 26,479 | $ 3,977 | $ 748,105 | $ 81,022 | $ 5,817 |
| *Sub-total* | $ 39,131,103 | $ 6,539,870 | $ 14,493,517 | $ 11,193,163 | $ 2,891,386 | $ 419,601 | $ 720,844 | $ 125,232 | $ 396,265 | $ 186,201 | $ 110,370 | $ 281,790 | $ 149,189 | $ 419,544 | $ 53,434 | $ 11,321 | $ 984,904 | $ 133,461 | $ 21,012 |
| **Maintenance** | | | | | | | | | | | | | | | | | | | |
| 1860 | $ 7,731,268 | $ 1,207,140 | $ 2,694,575 | $ 2,135,043 | $ 788,918 | $ 210,625 | $ 243,904 | $ 60,970 | $ - | $ - | $ - | $ 168,194 | $ 87,499 | $ 28,689 | $ 5,614 | $ 820 | $ 81,846 | $ 14,448 | $ 2,983 |
| **Billing and Collection** | | | | | | | | | | | | | | | | | | | |
| CWMR | $ 11,569,881 | $ 85,618 | $ 786,859 | $ 7,892,866 | $ 1,919,063 | $ 524,038 | $ 144,112 | $ 87,890 | $ - | $ - | $ - | $ - | $ - | $ 2,648 | $ 8,358 | $ 5,451 | $ 13,108 | $ 20,830 | $ 79,039 |
| CWNB | $ 53,658,191 | $ 10,020,274 | $ 20,427,727 | $ 14,803,541 | $ 3,647,892 | $ 439,135 | $ 757,228 | $ 143,263 | $ 214,580 | $ 377,381 | $ 221,848 | $ 57,741 | $ 56,682 | $ 630,434 | $ 56,698 | $ 17,039 | $ 1,588,324 | $ 173,484 | $ 24,918 |
| Sub-total | $ 65,228,072 | $ 10,105,893 | $ 21,214,587 | $ 22,696,408 | $ 5,566,955 | $ 963,173 | $ 901,341 | $ 231,153 | $ 214,580 | $ 377,381 | $ 221,848 | $ 57,741 | $ 56,682 | $ 633,082 | $ 65,056 | $ 22,490 | $ 1,601,432 | $ 194,315 | $ 103,957 |
| Total Operation, Maintenance and Billing | $ 112,090,444 | $ 17,852,902 | $ 38,402,678 | $ 36,024,614 | $ 9,247,259 | $ 1,593,399 | $ 1,866,088 | $ 417,355 | $ 610,845 | $ 563,581 | $ 332,218 | $ 507,725 | $ 293,370 | $ 1,081,315 | $ 124,104 | $ 34,631 | $ 2,668,182 | $ 342,224 | $ 127,952 |
| **Amortization Expense - Meters** | $ 48,046,754 | $ 7,338,595 | $ 16,381,193 | $ 12,979,616 | $ 4,796,089 | $ 1,280,457 | $ 1,482,770 | $ 370,657 | $ - | $ - | $ - | $ 1,022,504 | $ 531,936 | $ 495,103 | $ 108,847 | $ 29,655 | $ 956,218 | $ 211,752 | $ 61,360 |
| **Allocated PILs** | $ 1,743,524 | $ 271,997 | $ 607,022 | $ 480,921 | $ 177,757 | $ 47,456 | $ 54,967 | $ 13,738 | $ - | $ - | $ - | $ 37,998 | $ 19,716 | $ 6,949 | $ 1,366 | $ 223 | $ 19,228 | $ 3,447 | $ 740 |
| **Allocated Debt Return** | $ 9,703,661 | $ 1,513,814 | $ 3,378,410 | $ 2,676,586 | $ 989,312 | $ 264,116 | $ 305,923 | $ 76,459 | $ - | $ - | $ - | $ 211,477 | $ 109,728 | $ 38,676 | $ 7,604 | $ 1,238 | $ 107,016 | $ 19,185 | $ 4,116 |
| **Allocated Equity Return** | $ 13,826,842 | $ 2,157,048 | $ 4,813,929 | $ 3,813,893 | $ 1,409,680 | $ 376,342 | $ 435,913 | $ 108,947 | $ - | $ - | $ - | $ 301,335 | $ 156,353 | $ 55,110 | $ 10,835 | $ 1,765 | $ 152,489 | $ 27,337 | $ 5,865 |
| **Total** | **$ 174,274,053** | **$ 27,789,449** | **$ 59,977,704** | **$ 52,922,464** | **$ 15,565,309** | **$ 2,850,011** | **$ 3,939,433** | **$ 818,251** | **$ 587,688** | **$ 547,818** | **$ 322,537** | **$ 2,049,961** | **$ 594,738** | **$ 1,599,824** | **$ 242,930** | **$ 40,791** | **$ 3,710,332** | **$ 564,542** | **$ 150,269** |

## Scenario 2

***Accounts included in Directly Related Customer Costs Plus General Administration  Allocation***

| Accounts | Total | UR | R1 | R2 | GSe | GSd | UGe | UGd | St Lgt | Sen Lgt | USL | DGen | ST | AUR | AUGe | AUGd | AR | AGSe | AGSd |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Distribution Plant** | | | | | | | | | | | | | | | | | | | |
| CWMC | $ 694,202,434 | $ 106,031,524 | $ 236,683,303 | $ 187,535,687 | $ 69,296,185 | $ 18,500,659 | $ 21,423,768 | $ 5,355,435 | $ - | $ - | $ - | $ 14,773,631 | $ 7,685,668 | $ 7,153,485 | $ 1,572,666 | $ 428,474 | $ 13,815,900 | $ 3,059,495 | $ 886,553 |
| **Accumulated Amortization** | | | | | | | | | | | | | | | | | | | |
| Accum. Amortization of Electric Utility Plant - Meters only | $ (305,853,321) | $ (46,715,615) | $ (104,278,479) | $ (82,624,909) | $ (30,530,674) | $ (8,151,063) | $ (9,438,934) | $ (2,359,510) | $ - | $ - | $ - | $ (6,509,001) | $ (3,386,170) | $ (3,151,699) | $ (692,889) | $ (188,778) | $ (6,087,041) | $ (1,347,959) | $ (390,600) |
| **Meter Net Fixed Assets** | $ 388,349,114 | $ 59,315,909 | $ 132,404,824 | $ 104,910,779 | $ 38,765,511 | $ 10,349,595 | $ 11,984,835 | $ 2,995,925 | $ - | $ - | $ - | $ 8,264,630 | $ 4,299,499 | $ 4,001,786 | $ 879,777 | $ 239,696 | $ 7,728,858 | $ 1,711,535 | $ 495,954 |
| **Allocated General Plant Net Fixed Assets** | $ 20,106,446 | $ 3,131,034 | $ 7,018,857 | $ 5,573,456 | $ 2,047,536 | $ 547,056 | $ 630,319 | $ 158,176 | $ - | $ - | $ - | $ 413,481 | $ 226,959 | $ 77,721 | $ 15,208 | $ 2,458 | $ 217,354 | $ 38,605 | $ 8,226 |
| **Meter Net Fixed Assets Including General Plant** | $ 408,455,560 | $ 62,446,943 | $ 139,423,681 | $ 110,484,235 | $ 40,813,047 | $ 10,896,651 | $ 12,615,154 | $ 3,154,101 | $ - | $ - | $ - | $ 8,678,111 | $ 4,526,457 | $ 4,079,507 | $ 894,986 | $ 242,154 | $ 7,946,213 | $ 1,750,141 | $ 504,179 |
| **Misc Revenue** | | | | | | | | | | | | | | | | | | | |
| CWNB | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| NFA | $ (175,000) | $ (7,121) | $ (29,903) | $ (57,753) | $ (22,112) | $ (40,942) | $ (3,879) | $ (7,042) | $ (1,176) | $ (763) | $ (452) | $ (30) | $ - | $ (428) | $ (193) | $ (186) | $ (1,592) | $ (655) | $ (774) |
| LPHA | $ (10,962,172) | $ (1,337,787) | $ (3,575,627) | $ (2,995,413) | $ (1,032,677) | $ (670,817) | $ (202,350) | $ (161,863) | $ (21,981) | $ (15,001) | $ (9,229) | $ (31,048) | $ (516,365) | $ (76,901) | $ (9,633) | $ (26,535) | $ (191,210) | $ (38,748) | $ (48,989) |
| *Sub-total* | *$ (11,137,172)* | *$ (1,344,908)* | *$ (3,605,529)* | *$ (3,053,165)* | *$ (1,054,788)* | *$ (711,759)* | *$ (206,229)* | *$ (168,905)* | *$ (23,157)* | *$ (15,764)* | *$ (9,681)* | *$ (31,078)* | *$ (516,365)* | *$ (77,329)* | *$ (9,826)* | *$ (26,721)* | *$ (192,803)* | *$ (39,403)* | *$ (49,764)* |
| **Operation** | | | | | | | | | | | | | | | | | | | |
| CWMC | $ 11,898,370 | $ 1,817,341 | $ 4,056,663 | $ 3,214,291 | $ 1,187,711 | $ 317,094 | $ 367,195 | $ 91,790 | $ - | $ - | $ - | $ 253,214 | $ 131,729 | $ 122,608 | $ 26,955 | $ 7,344 | $ 236,799 | $ 52,439 | $ 15,195 |
| CCA | $ 27,232,733 | $ 4,722,529 | $ 10,436,853 | $ 7,978,872 | $ 1,703,675 | $ 102,506 | $ 353,648 | $ 33,442 | $ 396,265 | $ 186,201 | $ 110,370 | $ 28,575 | $ 17,460 | $ 296,936 | $ 26,479 | $ 3,977 | $ 748,105 | $ 81,022 | $ 5,817 |
| *Sub-total* | *$ 39,131,103* | *$ 6,539,870* | *$ 14,493,517* | *$ 11,193,163* | *$ 2,891,386* | *$ 419,601* | *$ 720,844* | *$ 125,232* | *$ 396,265* | *$ 186,201* | *$ 110,370* | *$ 281,790* | *$ 149,189* | *$ 419,544* | *$ 53,434* | *$ 11,321* | *$ 984,904* | *$ 133,461* | *$ 21,012* |
| **Maintenance** | | | | | | | | | | | | | | | | | | | |
| 1860 | $ 7,731,268 | $ 1,207,140 | $ 2,694,575 | $ 2,135,043 | $ 788,918 | $ 210,625 | $ 243,904 | $ 60,970 | $ - | $ - | $ - | $ 168,194 | $ 87,499 | $ 28,689 | $ 5,614 | $ 820 | $ 81,846 | $ 14,448 | $ 2,983 |
| **Billing and Collection** | | | | | | | | | | | | | | | | | | | |
| CWMR | $ 11,569,881 | $ 85,618 | $ 786,859 | $ 7,892,866 | $ 1,919,063 | $ 524,038 | $ 144,112 | $ 87,890 | $ - | $ - | $ - | $ - | $ - | $ 2,648 | $ 8,358 | $ 5,451 | $ 13,108 | $ 20,830 | $ 79,039 |
| CWNB | $ 53,658,191 | $ 10,020,274 | $ 20,427,727 | $ 14,803,541 | $ 3,647,892 | $ 439,135 | $ 757,228 | $ 143,263 | $ 214,580 | $ 377,381 | $ 221,848 | $ 57,741 | $ 56,682 | $ 630,434 | $ 56,698 | $ 17,039 | $ 1,588,324 | $ 173,484 | $ 24,918 |
| *Sub-total* | *$ 65,228,072* | *$ 10,105,893* | *$ 21,214,587* | *$ 22,696,408* | *$ 5,566,955* | *$ 963,173* | *$ 901,341* | *$ 231,153* | *$ 214,580* | *$ 377,381* | *$ 221,848* | *$ 57,741* | *$ 56,682* | *$ 633,082* | *$ 65,056* | *$ 22,490* | *$ 1,601,432* | *$ 194,315* | *$ 103,957* |
| Total Operation, Maintenance and Billing | $ 112,090,444 | $ 17,852,902 | $ 38,402,678 | $ 36,024,614 | $ 9,247,259 | $ 1,593,399 | $ 1,866,088 | $ 417,355 | $ 610,845 | $ 563,581 | $ 332,218 | $ 507,725 | $ 293,370 | $ 1,081,315 | $ 124,104 | $ 34,631 | $ 2,668,182 | $ 342,224 | $ 127,952 |
| **Amortization Expense - Meters** | $ 48,046,754 | $ 7,338,595 | $ 16,381,193 | $ 12,979,616 | $ 4,796,089 | $ 1,280,457 | $ 1,482,770 | $ 370,657 | $ - | $ - | $ - | $ 1,022,504 | $ 531,936 | $ 495,103 | $ 108,847 | $ 29,655 | $ 956,218 | $ 211,752 | $ 61,360 |
| ***Amortization Expense - General Plant assigned to Meters*** | $ 5,213,879 | $ 811,920 | $ 1,820,087 | $ 1,445,274 | $ 530,954 | $ 141,859 | $ 163,450 | $ 41,017 | $ - | $ - | $ - | $ 107,221 | $ 58,853 | $ 20,154 | $ 3,944 | $ 637 | $ 56,363 | $ 10,011 | $ 2,133 |
| **Admin and General** | $ 46,345,759 | $ 7,218,530 | $ 15,716,994 | $ 14,996,279 | $ 3,901,247 | $ 713,208 | $ 787,440 | $ 186,624 | $ 252,375 | $ 228,362 | $ 135,446 | $ 286,006 | $ 130,931 | $ 435,846 | $ 51,794 | $ 16,420 | $ 1,087,187 | $ 143,735 | $ 57,335 |
| **Allocated PILs** | $ 1,834,857 | $ 286,355 | $ 639,201 | $ 506,470 | $ 187,145 | $ 49,964 | $ 57,858 | $ 14,463 | $ - | $ - | $ - | $ 39,899 | $ 20,756 | $ 7,084 | $ 1,390 | $ 225 | $ 19,769 | $ 3,525 | $ 752 |
| **Allocated Debt Return** | $ 10,211,975 | $ 1,593,722 | $ 3,557,501 | $ 2,818,781 | $ 1,041,566 | $ 278,077 | $ 322,013 | $ 80,496 | $ - | $ - | $ - | $ 222,057 | $ 115,521 | $ 39,427 | $ 7,736 | $ 1,251 | $ 110,026 | $ 19,618 | $ 4,184 |
| **Allocated Equity Return** | $ 14,551,143 | $ 2,270,909 | $ 5,069,118 | $ 4,016,509 | $ 1,484,138 | $ 396,234 | $ 458,839 | $ 114,699 | $ - | $ - | $ - | $ 316,411 | $ 164,606 | $ 56,180 | $ 11,022 | $ 1,783 | $ 156,777 | $ 27,954 | $ 5,962 |
| **Total** | **$ 227,157,639** | **$ 36,028,026** | **$ 77,981,244** | **$ 69,734,378** | **$ 20,133,611** | **$ 3,741,439** | **$ 4,932,230** | **$ 1,056,407** | **$ 840,063** | **$ 776,180** | **$ 457,983** | **$ 2,470,746** | **$ 799,609** | **$ 2,057,781** | **$ 299,011** | **$ 57,881** | **$ 4,861,720** | **$ 719,415** | **$ 209,915** |

## Scenario 3

***Minimum System Customer Costs Adjusted for PLCC - High Limit Fixed Customer Charge***

| USoA Account # | Accounts | Total | UR | R1 | R2 | GSe | GSd | UGe | UGd | St Lgt | Sen Lgt | USL | DGen | ST | AUR | AUGe | AUGd | AR | AGSe | AGSd |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | **Distribution Plant** | | | | | | | | | | | | | | | | | | | |
| | CDMPP | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| | Poles, Towers and Fixtures | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| | BCP | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| | PNCP | $ 1,782,471,338 | $ 114,311,782 | $ 479,998,110 | $ 927,041,259 | $ 124,501,665 | $ 7,784,312 | $ 10,768,339 | $ 1,154,341 | $ 18,874,565 | $ 12,242,795 | $ 7,256,848 | $ 946,835 | $ 1,166,305 | $ 19,523,687 | $ 1,741,038 | $ 261,515 | $ 49,188,231 | $ 5,327,260 | $ 382,449 |
| | SNCP | $ 706,582,318 | $ 45,428,965 | $ 190,757,390 | $ 368,418,057 | $ 49,478,555 | $ - | $ 4,279,476 | $ - | $ 10,354,441 | $ 4,865,443 | $ 2,883,964 | $ - | $ - | $ 7,758,963 | $ 691,911 | $ - | $ 19,548,033 | $ 2,117,121 | $ - |
| | Overhead Conductors and Devices | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| | LTNCP | $ 1,697,882,714 | $ 109,049,530 | $ 457,901,781 | $ 884,365,657 | $ 118,770,331 | $ 6,716,014 | $ 10,272,627 | $ 956,959 | $ 18,005,690 | $ 11,679,208 | $ 6,922,785 | $ 457,694 | $ - | $ 18,624,930 | $ 1,660,891 | $ 194,412 | $ 46,923,891 | $ 5,082,024 | $ 298,292 |
| | CWCS | $ 857,967,029 | $ 88,595,292 | $ 293,695,191 | $ 449,054,167 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ 5,570,561 | $ - | $ - | $ 21,051,817 | $ - | $ - |
| | CWMC | $ 694,202,434 | $ 106,031,524 | $ 236,683,303 | $ 187,535,687 | $ 69,296,185 | $ 18,500,659 | $ 21,423,768 | $ 5,355,435 | $ - | $ - | $ - | $ 14,773,631 | $ 7,685,668 | $ 7,153,485 | $ 1,572,666 | $ 428,474 | $ 13,815,900 | $ 3,059,495 | $ 886,553 |
| | *Sub-total* | *$ 5,739,105,833* | *$ 463,417,093* | *$ 1,659,035,775* | *$ 2,816,414,828* | *$ 362,046,735* | *$ 33,000,985* | *$ 46,744,210* | *$ 7,466,735* | *$ 47,234,696* | *$ 28,787,447* | *$ 17,063,597* | *$ 16,178,160* | *$ 8,851,973* | *$ 58,631,627* | *$ 5,666,507* | *$ 884,401* | *$ 150,527,871* | *$ 15,585,899* | *$ 1,567,294* |
| | **Accumulated Amortization** | | | | | | | | | | | | | | | | | | | |
| | Accum. Amortization of Electric Utility Plant -Line Transformers, Services and Meters | $ (2,518,077,796) | $ (210,368,823) | $ (736,615,357) | $ (1,221,444,594) | $ (148,665,999) | $ (18,048,102) | $ (20,355,929) | $ (4,853,791) | $ (18,446,136) | $ (11,271,954) | $ (6,729,704) | $ (7,128,318) | $ (13,937,022) | $ (24,760,992) | $ (2,369,214) | $ (588,543) | $ (64,944,156) | $ (6,462,525) | $ (1,086,638) |
| | **Customer Related Net Fixed Assets** | $ 3,221,028,038 | $ 253,048,270 | $ 922,420,418 | $ 1,594,970,234 | $ 213,380,737 | $ 14,952,883 | $ 26,388,281 | $ 2,612,945 | $ 28,788,560 | $ 17,515,493 | $ 10,333,893 | $ 9,049,842 | $ (5,085,049) | $ 33,870,635 | $ 3,297,293 | $ 295,858 | $ 85,583,715 | $ 9,123,374 | $ 480,656 |
| | **Allocated General Plant Net Fixed Assets** | $ 172,019,990 | $ 13,357,339 | $ 48,898,045 | $ 84,733,868 | $ 11,270,451 | $ 790,375 | $ 1,387,840 | $ 137,956 | $ 1,530,302 | $ 5,840,238 | $ 550,800 | $ 452,765 | $ (268,426) | $ 657,821 | $ 56,998 | $ 3,034 | $ 2,406,823 | $ 205,787 | $ 7,972 |
| | **Customer Related NFA Including General Plant** | $ 3,393,048,028 | $ 266,405,609 | $ 971,318,463 | $ 1,679,704,102 | $ 224,651,187 | $ 15,743,258 | $ 27,776,121 | $ 2,750,900 | $ 30,318,862 | $ 23,355,731 | $ 10,884,693 | $ 9,502,607 | $ (5,353,474) | $ 34,528,456 | $ 3,354,291 | $ 298,892 | $ 87,990,539 | $ 9,329,161 | $ 488,628 |
| | **Misc Revenue** | | | | | | | | | | | | | | | | | | | |
| | CWNB | $ (1,383,530) | $ (258,364) | $ (526,711) | $ (381,697) | $ (94,058) | $ (11,323) | $ (19,524) | $ (3,694) | $ (5,533) | $ (9,730) | $ (5,720) | $ (1,489) | $ (1,461) | $ (16,255) | $ (1,462) | $ (439) | $ (40,954) | $ (4,473) | $ (643) |
| | SenLgt | $ (2,594,946) | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ (2,594,946) | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| | OM&A | $ (13,275,745) | $ (1,122,541) | $ (3,432,737) | $ (5,512,857) | $ (1,205,756) | $ (759,376) | $ (169,719) | $ (143,428) | $ (86,128) | $ (47,412) | $ (29,809) | $ (22,178) | $ (404,364) | $ (66,855) | $ (9,768) | $ (7,442) | $ (202,068) | $ (31,652) | $ (21,656) |
| | NFA | $ (175,000) | $ (7,121) | $ (29,903) | $ (57,753) | $ (22,112) | $ (40,942) | $ (3,879) | $ (7,042) | $ (1,176) | $ (763) | $ (452) | $ (30) | $ - | $ (428) | $ (193) | $ (186) | $ (1,592) | $ (655) | $ (774) |
| | LPHA | $ (10,962,172) | $ (1,337,787) | $ (3,575,627) | $ (2,995,413) | $ (1,032,677) | $ (670,817) | $ (202,350) | $ (161,863) | $ (21,981) | $ (15,001) | $ (9,229) | $ (31,048) | $ (516,365) | $ (76,901) | $ (9,633) | $ (26,535) | $ (191,210) | $ (38,748) | $ (48,989) |
| | *Sub-total* | *$ (28,391,394)* | *$ (2,725,813)* | *$ (7,564,978)* | *$ (8,947,719)* | *$ (2,354,602)* | *$ (1,482,458)* | *$ (395,472)* | *$ (316,027)* | *$ (114,818)* | *$ (2,667,852)* | *$ (45,210)* | *$ (54,744)* | *$ (922,191)* | *$ (160,439)* | *$ (21,055)* | *$ (34,602)* | *$ (435,824)* | *$ (75,528)* | *$ (72,062)* |
| | **Operating and Maintenance** | | | | | | | | | | | | | | | | | | | |
| | 1815-1855 | $ 24,472,536 | $ 1,778,070 | $ 7,016,493 | $ 12,876,313 | $ 1,466,065 | $ 115,944 | $ 134,622 | $ 28,662 | $ 231,570 | $ 140,309 | $ 83,708 | $ 7,464 | $ 119,071 | $ 88,991 | $ 6,505 | $ 778 | $ 349,340 | $ 26,264 | $ 2,369 |
| | 1830 & 1835 | $ 74,387,092 | $ 4,886,277 | $ 20,517,602 | $ 39,626,539 | $ 5,321,845 | $ 227,849 | $ 460,295 | $ 33,788 | $ 903,547 | $ 523,320 | $ 310,195 | $ 27,714 | $ 39,546 | $ 293,623 | $ 23,305 | $ 1,285 | $ 1,092,716 | $ 94,342 | $ 3,305 |
| | 1850 | $ 1,882,147 | $ 123,734 | $ 519,561 | $ 1,003,450 | $ 134,763 | $ 7,620 | $ 11,656 | $ 1,086 | $ 20,430 | $ 13,252 | $ 7,855 | $ 519 | $ - | $ 7,435 | $ 590 | $ 37 | $ 27,669 | $ 2,389 | $ 100 |
| | 1840 & 1845 | $ 898,987 | $ 59,053 | $ 247,964 | $ 478,904 | $ 64,317 | $ 4,021 | $ 5,563 | $ 596 | $ 9,750 | $ 6,325 | $ 3,749 | $ 489 | $ - | $ 3,548 | $ 282 | $ 23 | $ 13,205 | $ 1,140 | $ 58 |
| | CWMC | $ 11,898,370 | $ 1,817,341 | $ 4,056,663 | $ 3,214,291 | $ 1,187,711 | $ 317,094 | $ 367,195 | $ 91,790 | $ - | $ - | $ - | $ 253,214 | $ 131,729 | $ 122,608 | $ 26,955 | $ 7,344 | $ 236,799 | $ 52,439 | $ 15,195 |
| | CCA | $ 27,232,733 | $ 4,722,529 | $ 10,436,853 | $ 7,978,872 | $ 1,703,675 | $ 102,506 | $ 353,648 | $ 33,442 | $ 396,265 | $ 186,201 | $ 110,370 | $ 28,575 | $ 17,460 | $ 296,936 | $ 26,479 | $ 3,977 | $ 748,105 | $ 81,022 | $ 5,817 |
| | O&M | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| | 1830 | $ 9,631,000 | $ 632,803 | $ 2,657,157 | $ 5,131,882 | $ 689,212 | $ 24,716 | $ 59,611 | $ 3,665 | $ 121,435 | $ 67,773 | $ 40,172 | $ 3,006 | $ 4,290 | $ 38,027 | $ 3,018 | $ 139 | $ 141,517 | $ 12,218 | $ 358 |
| | 1835 | $ 17,978,823 | $ 1,180,440 | $ 4,956,697 | $ 9,573,085 | $ 1,285,666 | $ 70,204 | $ 111,199 | $ 10,411 | $ 204,299 | $ 126,425 | $ 74,938 | $ 8,539 | $ 12,185 | $ 70,931 | $ 5,630 | $ 396 | $ 263,970 | $ 22,790 | $ 1,018 |
| | 1855 | $ 15,090,458 | $ 1,583,420 | $ 5,249,070 | $ 8,025,725 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ 35,283 | $ - | $ - | $ 196,959 | $ - | $ - |
| | 1840 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| | 1845 | $ 694,161 | $ 45,598 | $ 191,468 | $ 369,790 | $ 49,663 | $ 3,105 | $ 4,295 | $ 460 | $ 7,529 | $ 4,884 | $ 2,895 | $ 378 | $ - | $ 2,740 | $ 217 | $ 18 | $ 10,196 | $ 880 | $ 45 |
| | 1860 | $ 7,731,268 | $ 1,207,140 | $ 2,694,575 | $ 2,135,043 | $ 788,918 | $ 210,625 | $ 243,904 | $ 60,970 | $ - | $ - | $ - | $ 168,194 | $ 87,499 | $ 28,689 | $ 5,614 | $ 820 | $ 81,846 | $ 14,448 | $ 2,983 |
| | *Sub-total* | *$ 191,897,575* | *$ 18,036,404* | *$ 58,544,103* | *$ 90,413,894* | *$ 12,691,835* | *$ 1,083,686* | *$ 1,751,988* | *$ 264,870* | *$ 1,894,825* | *$ 1,068,489* | *$ 633,881* | *$ 498,093* | *$ 411,780* | *$ 988,812* | *$ 98,595* | *$ 14,816* | *$ 3,162,323* | *$ 307,932* | *$ 31,249* |
| | **Billing and Collection** | | | | | | | | | | | | | | | | | | | |
| | CWNB | $ 60,253,891 | $ 11,251,973 | $ 22,938,717 | $ 16,623,202 | $ 4,096,294 | $ 493,114 | $ 850,307 | $ 160,873 | $ 240,956 | $ 423,768 | $ 249,118 | $ 64,839 | $ 63,649 | $ 707,928 | $ 63,667 | $ 19,133 | $ 1,783,562 | $ 194,809 | $ 27,981 |
| | CWMR | $ 11,569,881 | $ 85,618 | $ 786,859 | $ 7,892,866 | $ 1,919,063 | $ 524,038 | $ 144,112 | $ 87,890 | $ - | $ - | $ - | $ - | $ - | $ 2,648 | $ 8,358 | $ 5,451 | $ 13,108 | $ 20,830 | $ 79,039 |
| | BDHA | $ 18,059,732 | $ 2,195,768 | $ 7,173,427 | $ 4,720,004 | $ 1,339,894 | $ 1,469,994 | $ 221,676 | $ 264,073 | $ 19,121 | $ 24,887 | $ 4,913 | $ 2,896 | $ 116,098 | $ 149,781 | $ 16,349 | $ 27,643 | $ 262,930 | $ 35,049 | $ 15,229 |
| | *Sub-total* | *$ 89,883,504* | *$ 13,533,360* | *$ 30,899,004* | *$ 29,236,072* | *$ 7,355,250* | *$ 2,487,145* | *$ 1,216,096* | *$ 512,836* | *$ 260,077* | *$ 448,655* | *$ 254,031* | *$ 67,735* | *$ 179,747* | *$ 860,356* | *$ 88,374* | *$ 52,228* | *$ 2,059,600* | *$ 250,688* | *$ 122,249* |
| | *Sub Total Operating, Maintenance and Biling* | *$ 281,781,079* | *$ 31,569,764* | *$ 89,443,107* | *$ 119,649,967* | *$ 20,047,086* | *$ 3,570,831* | *$ 2,968,084* | *$ 777,706* | *$ 2,154,902* | *$ 1,517,144* | *$ 887,912* | *$ 565,828* | *$ 591,527* | *$ 1,849,169* | *$ 186,969* | *$ 67,044* | *$ 5,221,923* | *$ 558,620* | *$ 153,498* |
| | **Amortization Expense - Customer Related** | $ 167,330,506 | $ 15,781,630 | $ 49,748,873 | $ 74,296,815 | $ 11,859,010 | $ 1,861,941 | $ 2,134,467 | $ 516,673 | $ 1,105,968 | $ 674,403 | $ 402,569 | $ 1,057,886 | $ 1,147,740 | $ 1,703,267 | $ 209,034 | $ 53,010 | $ 4,157,707 | $ 517,450 | $ 102,064 |
| | **Amortization Expense - General Plant assigned to Meters** | $ 43,672,917 | $ 3,463,743 | $ 12,679,939 | $ 21,972,663 | $ 2,922,584 | $ 204,955 | $ 359,886 | $ 35,774 | $ 396,828 | $ 580,211 | $ 142,830 | $ 117,408 | $ (69,606) | $ 170,582 | $ 14,780 | $ 787 | $ 624,123 | $ 53,363 | $ 2,067 |
| | **Admin and General** | $ 116,570,788 | $ 12,764,720 | $ 36,606,217 | $ 49,807,731 | $ 8,457,494 | $ 1,598,310 | $ 1,252,453 | $ 347,759 | $ 890,312 | $ 614,745 | $ 362,003 | $ 318,736 | $ 263,999 | $ 745,346 | $ 78,031 | $ 31,788 | $ 2,127,742 | $ 234,622 | $ 68,782 |
| | **Allocated PILs** | $ 15,213,402 | $ 1,221,623 | $ 4,453,101 | $ 7,699,921 | $ 1,030,123 | $ 72,187 | $ 127,393 | $ 12,614 | $ 138,980 | $ 84,558 | $ 49,888 | $ 43,689 | $ (24,549) | $ 59,959 | $ 5,209 | $ 277 | $ 218,909 | $ 18,789 | $ 729 |
| | **Allocated Debt Return** | $ 84,670,851 | $ 6,798,994 | $ 24,783,930 | $ 42,854,245 | $ 5,733,192 | $ 401,760 | $ 709,010 | $ 70,206 | $ 773,502 | $ 470,613 | $ 277,655 | $ 243,154 | $ (136,627) | $ 333,705 | $ 28,992 | $ 1,544 | $ 1,218,348 | $ 104,574 | $ 4,055 |
| | **Allocated Equity Return** | $ 120,648,323 | $ 9,687,953 | $ 35,314,864 | $ 61,063,433 | $ 8,169,281 | $ 572,471 | $ 1,010,275 | $ 100,037 | $ 1,102,170 | $ 670,581 | $ 395,633 | $ 346,473 | $ (194,681) | $ 475,500 | $ 41,311 | $ 2,200 | $ 1,736,035 | $ 149,008 | $ 5,779 |
| | **PLCC Adjustment for Line Transformer** | $ 25,386,774 | $ - | $ - | $ - | $ 17,295,138 | $ 2,487,654 | $ 3,864,026 | $ 354,414 | $ - | $ - | $ - | $ - | $ - | $ - | $ 331,389 | $ 32,543 | $ - | $ 963,055 | $ 58,554 |
| | **PLCC Adjustment for Primary Costs** | $ 114,513,741 | $ 7,404,258 | $ 31,135,340 | $ 60,192,442 | $ 9,586,924 | $ 589,636 | $ 828,694 | $ 87,424 | $ 1,381,223 | $ - | $ - | $ 71,189 | $ 1,713 | $ 703,206 | $ 58,804 | $ 6,788 | $ 2,242,555 | $ 210,902 | $ 12,643 |
| | **PLCC Adjustment for Secondary Costs** | $ 73,777,131 | $ 4,828,189 | $ 20,313,660 | $ 38,709,309 | $ 6,037,230 | $ - | $ 519,948 | $ - | $ 1,280,989 | $ - | $ - | $ - | $ - | $ 463,645 | $ 36,514 | $ - | $ 1,456,228 | $ 131,419 | $ - |
| | **Total** | **$ 587,818,826** | **$ 66,330,166** | **$ 194,016,053** | **$ 269,495,304** | **$ 22,944,874** | **$ 3,722,708** | **$ 2,953,429** | **$ 1,102,903** | **$ 3,785,632** | **$ 1,944,402** | **$ 2,473,280** | **$ 2,567,241** | **$ 653,900** | **$ 4,010,238** | **$ 116,563** | **$ 82,717** | **$ 11,170,180** | **$ 255,522** | **$ 193,714** |

# 2023 COST ALLOCATION MODEL

This schedule has been filed separately in MS Excel format.

## 2023 Rate Design Including 7th Year of Residential Phase-in to All-Fixed Rates for R1 and R2 Rate Classes

| | Number of Customers | GWh* | kWs | Revenue from 2023 CAM (A) | Allocated Cost from 2023 CAM (B) | 2023 Misc Revenue (C) | Revenue from Rates (D=A-C) | R/C Ratio from the CAM (E=A/B) | Target 2023 R/C Ratio (F) | Total Revenue to be Collected from Rates (G=BxF) | Shifted Revenue (H=G-A) |
|---|---|---|---|---|---|---|---|---|---|---|---|
| UR | 246,136 | 2,025 | - | $ 112,317,608 | $ 107,498,074 | $ 4,387,276 | $ 107,930,332 | 1.04 | 1.04 | $ 112,317,608 | $ - |
| R1 | 543,965 | 5,083 | - | $ 419,394,873 | $ 367,313,862 | $ 12,021,983 | $ 407,372,890 | 1.14 | 1.14 | $ 419,103,596 | $ (291,277) |
| R2 | 337,179 | 4,828 | - | $ 646,452,197 | $ 676,443,073 | $ 14,737,593 | $ 631,714,604 | 0.96 | 0.96 | $ 646,452,197 | $ - |
| Seasonal-R2 | 78,677 | | | | | | | | | | |
| GSe | 88,795 | 1,995 | - | $ 168,811,119 | $ 166,627,672 | $ 3,614,492 | $ 165,196,627 | 1.01 | 1.01 | $ 168,811,119 | $ - |
| GSd | 5,343 | 2,183 | 6,995,713 | $ 138,845,620 | $ 150,773,769 | $ 2,124,771 | $ 136,720,849 | 0.92 | 0.92 | $ 138,845,620 | $ - |
| UGe | 18,432 | 547 | - | $ 23,343,731 | $ 24,226,639 | $ 590,543 | $ 22,753,188 | 0.96 | 0.96 | $ 23,343,731 | $ - |
| UGd | 1,743 | 883 | 2,304,119 | $ 27,120,784 | $ 28,091,463 | $ 439,538 | $ 26,681,246 | 0.97 | 0.97 | $ 27,120,784 | $ - |
| St Lgt | 5,494 | 83 | - | $ 9,474,508 | $ 9,741,729 | $ 247,580 | $ 9,226,928 | 0.97 | 0.97 | $ 9,474,508 | $ - |
| Sen Lgt | 19,409 | 11 | - | $ 5,325,001 | $ 4,781,961 | $ 2,735,960 | $ 2,589,041 | 1.11 | 1.11 | $ 5,325,001 | $ - |
| USL | 5,752 | 33 | - | $ 3,507,945 | $ 2,958,691 | $ 86,988 | $ 3,420,958 | 1.19 | 1.14 | $ 3,375,855 | $ (132,090) |
| DGen | 1,489 | 30 | 210,462 | $ 5,711,115 | $ 6,893,699 | $ 77,487 | $ 5,633,628 | 0.83 | 0.83 | $ 5,711,115 | $ - |
| ST | 910 | 15,070 | 30,805,724 | $ 62,870,242 | $ 72,401,495 | $ 1,258,437 | $ 61,611,805 | 0.87 | 0.87 | $ 62,870,242 | $ - |
| AUR | 15,476 | 118 | - | $ 5,865,642 | $ 6,220,287 | $ 261,832 | $ 5,603,809 | 0.94 | 0.94 | $ 5,865,642 | $ - |
| AUGe | 1,380 | 41 | - | $ 1,049,887 | $ 1,325,961 | $ 33,236 | $ 1,016,651 | 0.79 | 0.80 | $ 1,060,769 | $ 10,882 |
| AUGd | 207 | 118 | 334,039 | $ 1,115,437 | $ 1,511,348 | $ 41,359 | $ 1,074,078 | 0.74 | 0.80 | $ 1,209,078 | $ 93,641 |
| AR | 38,991 | 336 | - | $ 17,861,395 | $ 20,800,134 | $ 719,016 | $ 17,142,378 | 0.86 | 0.86 | $ 17,861,395 | $ - |
| AGSe | 4,223 | 117 | - | $ 4,121,387 | $ 4,407,744 | $ 114,255 | $ 4,007,132 | 0.94 | 0.94 | $ 4,121,387 | $ - |
| AGSd | 303 | 231 | 646,691 | $ 3,089,334 | $ 4,260,223 | $ 90,831 | $ 2,998,503 | 0.73 | 0.80 | $ 3,408,178 | $ 318,844 |
| **TOTAL** | **1,413,905** | **33,735** | **41,296,748** | **1,656,277,824** | **1,656,277,824** | **43,583,177** | **1,612,694,647** | | | **1,656,277,824** | **(0)** |

**Derivation of 2023 Fixed Charge for Non-Residential Classes**

| | Current (2022) Fixed Charge for Non-Residential Classes ($/month) (I) | Fixed Charge Ceiling for Non-Residential Classes from CAM ($/month) (J) | Is Current Fixed Charge higher than CAM Ceiling? (K) If I > J then "Yes" else "No" | Current (2022) F/V Split for Non-Residential Classes (L) | 2023 Revenue from Fixed Charge using Current F/V Split (M=(G-C) x L) | 2023 Fixed Charge Using Current F/V Split ($/month)* (N=M / Number of Customers / 12) | 2023 Base Fixed Charge for Non-Residential Classes ($/month) (O) If K="Yes" then fixed charge = Min(I, N), else fixed charge = N |
|---|---|---|---|---|---|---|---|
| UR | | | | | | | |
| R1 | | | | | | | |
| R2 | | | | | | | |
| Seasonal-R2 | | | | | | | |
| GSe | $ 34.13 | $ 21.53 | Yes | 20% | $ 33,388,232 | $ 31.33 | $ 31.33 |
| GSd | $ 113.67 | $ 58.07 | Yes | 5% | $ 6,463,750 | $ 100.82 | $ 100.82 |
| UGe | $ 26.95 | $ 13.35 | Yes | 24% | $ 5,394,992 | $ 24.39 | $ 24.39 |
| UGd | $ 104.78 | $ 52.73 | Yes | 7% | $ 1,927,578 | $ 92.16 | $ 92.16 |
| St Lgt | $ 11.16 | $ 15.27 | No | 2% | $ 198,143 | $ 3.01 | $ 3.01 |
| Sen Lgt | $ 3.25 | $ 16.70 | No | 27% | $ 701,084 | $ 3.01 | $ 3.01 |
| USL | $ 39.31 | $ 35.83 | Yes | 77% | $ 2,534,994 | $ 36.72 | $ 36.72 |
| DGen | $ 199.36 | $ 143.65 | Yes | 61% | $ 3,409,748 | $ 190.79 | $ 190.79 |
| ST | $ 1,175.74 | $ 59.88 | Yes | 19% | $ 11,527,707 | $ 1,055.65 | $ 1,055.65 |
| AUR | | | | | | | |
| AUGe | $ 26.36 | $ 7.04 | Yes | 41% | $ 423,734 | $ 25.59 | $ 25.59 |
| AUGd | $ 146.47 | $ 33.25 | Yes | 33% | $ 380,420 | $ 152.93 | $ 146.47 |
| AR | | | | | | | |
| AGSe | $ 39.96 | $ 5.04 | Yes | 49% | $ 1,944,664 | $ 38.38 | $ 38.38 |
| AGSd | $ 170.26 | $ 53.25 | Yes | 20% | $ 658,094 | $ 180.90 | $ 170.26 |

| | Base Fixed Charge ($/month) (P): UR, AUR, and AR=100% Fixed; R1 and R2 = Refer to RRWF; Seasonal-R2=See table below; Non-Residential Classes=O | Revenue from Fixed Charge ($) (Q = P x 12 x Number of Customers) | Revenue from Volumetric Charge ($) (R=G-C-Q) | Base Volumetric Charge ($/kWh) (S=R/kWh) | Base Volumetric Charge ($/kW) (T=R/kW) | CSTA Rate Adders ($/kW) (U) | Hopper Foundry Rate Adder ($/kW) (V) | Total Volumetric Charge ($/kW) (W=T+U+V) |
|---|---|---|---|---|---|---|---|---|
| UR | $ 36.54 | $ 107,930,332 | $ - | | | | | |
| R1 | $ 58.22 | $ 380,006,381 | $ 27,075,232 | $ 0.0053 | | | | |
| R2 | $ 118.64 | $ 480,053,439 | $ 90,059,988 | $ 0.0187 | | | | |
| Seasonal-R2 | $ 65.25 | $ 61,601,178 | $ - | | | | | |
| GSe | $ 31.33 | $ 33,388,232 | $ 131,808,395 | $ 0.0661 | | | | |
| GSd | $ 100.82 | $ 6,463,750 | $ 130,257,099 | | $ 18.6196 | $ 0.0973 | $ 0.0126 | $ 18.7295 |
| UGe | $ 24.39 | $ 5,394,992 | $ 17,358,196 | $ 0.0317 | | | | |
| UGd | $ 92.16 | $ 1,927,578 | $ 24,753,668 | | $ 10.7432 | $ 0.1313 | | $ 10.8745 |
| St Lgt | $ 3.01 | $ 198,143 | $ 9,028,785 | $ 0.1083 | | | | |
| Sen Lgt | $ 3.01 | $ 701,084 | $ 1,887,957 | $ 0.1658 | | | | |
| USL | $ 36.72 | $ 2,534,994 | $ 753,873 | $ 0.0231 | | | | |
| DGen | $ 190.79 | $ 3,409,748 | $ 2,223,880 | | $ 10.5667 | $ 0.4897 | | $ 11.0564 |
| ST | N/A** | $ 11,527,707 | $ 50,084,098 | | N/A** | | | N/A** |
| AUR | $ 30.17 | $ 5,603,809 | $ - | | | | | |
| AUGe | $ 25.59 | $ 423,734 | $ 603,799 | $ 0.0148 | | | | |
| AUGd | $ 146.47 | $ 364,359 | $ 803,360 | | $ 2.4050 | $ 0.3157 | | $ 2.7207 |
| AR | $ 36.64 | $ 17,142,378 | $ - | | | | | |
| AGSe | $ 38.38 | $ 1,944,664 | $ 2,062,467 | $ 0.0176 | | | | |
| AGSd | $ 170.26 | $ 619,398 | $ 2,697,950 | | $ 4.1719 | $ 0.2540 | | $ 4.4259 |
| **TOTAL** | | **1,121,235,899** | **491,458,748** | | | | | |

**Derivation of 2023 Mitigated Fixed Charge for Seasonal Customers Moving to R2 Class**

| Current (2022) Fixed Charge for Seasonal Customers ($/month) (A1) | All-Fixed Distribution Charge for R2 Class ($/month) (B1 = ($G_{R2}$ - $C_{R2}$)/Number of Customers($_{R2+Seasonal-R2}$/12) | Phase-in Period (in years) (C1) | Annual Increase in Seasonal-R2 Fixed Charge ($) (D1 = (B1-A1)/C1) | 2023 Fixed Charge for Seasonal Customers Moving to R2 Class ($/month) (E1=A1+D1) |
|---|---|---|---|---|
| $58.43 | $126.59 | 10 | $6.82 | $65.25 |

| | | |
|---|---|---|
| **Total Revenue from Rates (Q+R)** | **$** | **1,612,694,647** |
| **Miscellaneous Revenue (C)** | **$** | **43,583,177** |
| **Total Revenue Requirement (Q+R+C)** | **$** | **1,656,277,824** |

* GWh shown for R2 class includes consumption associated with Seasonal customers moving to the R2 class.
** Final ST rates are provided in Schedule 4.1.

## 2024 Rate Design Including 8th and Final Year of Residential Phase-in to All-Fixed Rates for R1 and R2 Rate Classes

| | Number of Customers | GWh* | kWs | Revenue - with 2023 Rates and 2024 Charge Determinants (Y) | 2023 Revenue (Z) | 2024 Rates Revenue Requirement (A) = Y*$X_{RevReq}$ | 2024 Misc Revenue (B) = $C_{2023}$*$X_{MiscRev}$ | 2024 Total Revenue (C) = A+B |
|---|---|---|---|---|---|---|---|---|
| UR | 249,127 | 2,045 | - | $ 109,237,192 | $ 112,317,608 | $ 113,610,322 | $ 4,418,004 | $ 118,028,325 |
| R1 | 548,767 | 5,120 | - | $ 410,659,965 | $ 419,103,596 | $ 427,100,055 | $ 12,106,183 | $ 439,206,238 |
| R2 | 339,354 | 4,822 | - | $ 634,609,926 | $ 646,452,197 | $ 660,015,482 | $ 14,840,813 | $ 674,856,295 |
| Seasonal-R2 | 78,584 | | | | | | | |
| GSe | 88,831 | 1,982 | - | $ 164,336,838 | $ 168,811,119 | $ 170,915,790 | $ 3,639,807 | $ 174,555,597 |
| GSd | 5,393 | 2,183 | 6,997,873 | $ 136,821,785 | $ 138,845,620 | $ 142,299,218 | $ 2,139,652 | $ 144,438,870 |
| UGe | 18,524 | 547 | - | $ 22,767,761 | $ 23,343,731 | $ 23,679,231 | $ 594,679 | $ 24,273,910 |
| UGd | 1,753 | 885 | 2,302,095 | $ 26,670,884 | $ 27,120,784 | $ 27,738,609 | $ 442,617 | $ 28,181,226 |
| St Lgt | 5,536 | 83 | - | $ 9,187,601 | $ 9,474,508 | $ 9,555,411 | $ 249,314 | $ 9,804,724 |
| Sen Lgt | 19,086 | 11 | - | $ 2,534,291 | $ 5,325,001 | $ 2,635,747 | $ 2,755,122 | $ 5,390,869 |
| USL | 5,793 | 33 | - | $ 3,312,451 | $ 3,375,855 | $ 3,445,059 | $ 87,597 | $ 3,532,656 |
| DGen | 1,576 | 31 | 216,624 | $ 5,896,414 | $ 5,711,115 | $ 6,132,467 | $ 78,030 | $ 6,210,497 |
| ST | 917 | 15,126 | 30,920,895 | $ 61,887,715 | $ 62,870,242 | $ 64,365,287 | $ 1,267,250 | $ 65,632,537 |
| AUR | 15,550 | 119 | - | $ 5,629,656 | $ 5,865,642 | $ 5,855,030 | $ 263,666 | $ 6,118,696 |
| AUGe | 1,392 | 41 | - | $ 1,038,121 | $ 1,060,769 | $ 1,079,681 | $ 33,469 | $ 1,113,149 |
| AUGd | 207 | 119 | 334,225 | $ 1,168,343 | $ 1,209,078 | $ 1,215,115 | $ 41,649 | $ 1,256,764 |
| AR | 39,198 | 334 | - | $ 17,234,518 | $ 17,861,395 | $ 17,924,473 | $ 724,052 | $ 18,648,526 |
| AGSe | 4,213 | 116 | - | $ 3,983,824 | $ 4,121,387 | $ 4,143,310 | $ 115,055 | $ 4,258,365 |
| AGSd | 306 | 229 | 640,641 | $ 3,297,381 | $ 3,408,178 | $ 3,429,386 | $ 91,467 | $ 3,520,853 |
| **TOTAL** | **1,424,106** | **33,826** | **41,412,352** | **1,620,274,664** | **1,656,277,824** | **1,685,139,673** | **43,888,426** | **1,729,028,099** |

| | Derivation of 2024 Fixed Charge for Non-Residential Classes | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Current (2023) Fixed Charge for Non-Residential Classes ($/month) (D) | Fixed Charge Ceiling for Non-Residential Classes from CAM ($/month) (E) | Is Current Fixed Charge higher than CAM Ceiling? (F) If D > E then "Yes" else "No" | Current (2023) F/V Split for Non-Residential Classes (G) | 2024 Revenue from Fixed Charge using Current F/V Split (H) = A x G | 2024 Fixed Charge Using Current F/V Split ($/month)* (I) = H / Number of Customers / 12 | 2024 Base Fixed Charge for Non-Residential Classes ($/month) (J) If F="Yes" then fixed charge = Min(D, I), else fixed charge = I | Base Fixed Charge ($/month) (K): UR, R1, R2, AUR, and AR = 100% Fixed; Seasonal-R2 = See table below; Non-Residential Classes = J | Revenue from Fixed Charge (L) = K x Number of Customers x 12 | Revenue from Volumetric Charge (M) = A - L | Base Volumetric Charge ($/kWh) (N) = M/kWh | Base Volumetric Charge ($/kW) (O) = M/kW | CSTA Rate Adders ($/kW) (P) | Hopper Foundry Rate Adder ($/kW) (Q) | Total Volumetric Charge ($/kW) (R) = O+P+Q |
| UR | | | | | | | | $ 38.00 | $ 113,610,322 | $ - | | | | | |
| R1 | | | | | | | | $ 64.86 | $ 427,100,055 | $ - | | | | | |
| R2 | | | | | | | | $ 131.60 | $ 535,914,630 | $ 55,620,379 | $ 0.0115 | | | | |
| Seasonal-R2 | | | | | | | | $ 72.62 | $ 68,480,474 | $ - | | | | | |
| GSe | $ 31.33 | $ 21.53 | Yes | 20% | $ 34,544,144 | $ 32.41 | $ 31.33 | $ 31.33 | $ 33,396,951 | $ 137,518,840 | $ 0.0694 | | | | |
| GSd | $ 100.82 | $ 58.07 | Yes | 5% | $ 6,727,479 | $ 103.96 | $ 100.82 | $ 100.82 | $ 6,524,466 | $ 135,774,752 | | $ 19.4023 | $ 0.0973 | $ 0.0131 | $ 19.5127 |
| UGe | $ 24.39 | $ 13.35 | Yes | 24% | $ 5,614,565 | $ 25.26 | $ 24.39 | $ 24.39 | $ 5,421,686 | $ 18,257,545 | $ 0.0334 | | | | |
| UGd | $ 92.16 | $ 52.73 | Yes | 7% | $ 2,003,967 | $ 95.25 | $ 92.16 | $ 92.16 | $ 1,938,965 | $ 25,799,644 | | $ 11.2070 | $ 0.1313 | | $ 11.3383 |
| St Lgt | $ 3.01 | $ 15.27 | No | 2% | $ 205,197 | $ 3.09 | $ 3.09 | $ 3.09 | $ 205,197 | $ 9,350,214 | $ 0.1126 | | | | |
| Sen Lgt | $ 3.01 | $ 16.70 | No | 27% | $ 713,731 | $ 3.12 | $ 3.12 | $ 3.12 | $ 713,731 | $ 1,922,016 | $ 0.1728 | | | | |
| USL | $ 36.72 | $ 35.83 | Yes | 77% | $ 2,655,384 | $ 38.20 | $ 36.72 | $ 36.72 | $ 2,552,516 | $ 892,544 | $ 0.0271 | | | | |
| DGen | $ 190.79 | $ 143.65 | Yes | 61% | $ 3,711,670 | $ 196.30 | $ 190.79 | $ 190.79 | $ 3,607,419 | $ 2,525,048 | | $ 11.6564 | $ 0.4897 | | $ 12.1461 |
| ST | $ 1,055.65 | $ 59.88 | Yes | 19% | $ 12,042,890 | $ 1,094.41 | $ 1,055.65 | N/A** | $ 11,616,373 | $ 52,748,914 | | N/A** | | | N/A** |
| AUR | | | | | | | | $ 31.38 | $ 5,855,030 | $ - | | | | | |
| AUGe | $ 25.59 | $ 7.04 | Yes | 41% | $ 445,238 | $ 26.66 | $ 25.59 | $ 25.59 | $ 427,400 | $ 652,280 | $ 0.0158 | | | | |
| AUGd | $ 146.47 | $ 33.25 | Yes | 31% | $ 379,148 | $ 152.34 | $ 146.47 | $ 146.47 | $ 364,535 | $ 850,581 | | $ 2.5449 | $ 0.3157 | | $ 2.8606 |
| AR | | | | | | | | $ 38.11 | $ 17,924,473 | $ - | | | | | |
| AGSe | $ 38.38 | $ 5.04 | Yes | 49% | $ 2,010,752 | $ 39.77 | $ 38.38 | $ 38.38 | $ 1,940,314 | $ 2,202,996 | $ 0.0189 | | | | |
| AGSd | $ 170.26 | $ 53.25 | Yes | 19% | $ 640,317 | $ 174.52 | $ 170.26 | $ 170.26 | $ 624,673 | $ 2,804,712 | | $ 4.3780 | $ 0.2540 | | $ 4.6320 |
| **TOTAL** | | | | | | | | | **$ 1,238,219,209** | **$ 446,920,465** | | | | | |

| Derivation of 2024 Mitigated Fixed Charge for Seasonal Customers Moving to R2 Class | | | | |
|---|---|---|---|---|
| **Current (2023) Fixed Charge for Seasonal-R2 Customers ($/month)** (A1) | **All-Fixed Distribution Charge for R2 Class ($/month)** (B1 = $A_{R2}$/Number of Customers$_{(R2+Seasonal\text{-}R2)}$/12) | **Phase-in Period (in years)** (C1) | **Annual Increase in Seasonal-R2 Fixed Charge ($)** (D1 = (B1-A1)/C1) | **2024 Fixed Charge for Seasonal Customers Moving to R2 Class ($/month)** (E1=A1+D1) |
| $ 65.25 | $ 131.60 | 9 | $ 7.37 | $ 72.62 |

| | | |
|---|---|---|
| **Total Revenue from Rates (L+M)** | **$** | **1,685,139,673** |
| **Miscellaneous Revenue (B)** | **$** | **43,888,426** |
| **Total Revenue Reqquirement (L+M+B)** | **$** | **1,729,028,099** |

* GWh shown for R2 class includes consumption associaed with Seasonal customers moving to the R2 class.

** Final ST rates are provided in Schedule 4.1.

**2024 Adjustments (from 2023 Revenue Requirement) by Rate Class**

| | 2023 | 2024 | % (X) |
|---|---|---|---|
| Revenue Requirement*** | $ 1,620,274,664 | $ 1,685,139,673 | 104.00% |
| Alloc Cost | $ 1,656,277,824 | $ 1,729,028,099 | 104.39% |
| Misc Revenue | $ 43,583,177 | $ 43,888,426 | 100.70% |

*** 2023: Revenue with 2023 rates and 2024 charge determinants
2024: 2024 Revenue before rate design adjustments

## 2025 Rate Design

| | Number of Customers | GWh* | kWs | Revenue - with 2024 Rates and 2025 Charge Determinants | 2024 Revenue | 2025 Rates Revenue Requirement | 2025 Misc Revenue | 2025 Total Revenue |
|---|---|---|---|---|---|---|---|---|
| | | | | (Y) | (Z) | (A) = Y*$X_{RevReq}$ | (B) = $B_{2024}$*$X_{MiscRev}$ | (C) = A+B |
| UR | 252,081 | 2,031 | - | $ 114,948,898 | $ 118,028,325 | $ 118,891,425 | $ 4,438,137 | $ 123,329,561 |
| R1 | 553,488 | 5,073 | - | $ 430,790,438 | $ 439,206,238 | $ 445,565,725 | $ 12,161,351 | $ 457,727,075 |
| R2 | 341,471 | 4,739 | - | $ 662,294,527 | $ 674,856,295 | $ 685,009,960 | $ 14,908,443 | $ 699,918,402 |
| Seasonal-R2 | 78,475 | | | | | | | |
| GSe | 88,891 | 1,937 | - | $ 167,825,316 | $ 174,555,597 | $ 173,581,403 | $ 3,656,394 | $ 177,237,797 |
| GSd | 5,439 | 2,149 | 6,886,927 | $ 140,202,831 | $ 144,438,870 | $ 145,011,520 | $ 2,149,403 | $ 147,160,923 |
| UGe | 18,620 | 538 | - | $ 23,400,935 | $ 24,273,910 | $ 24,203,542 | $ 597,389 | $ 24,800,931 |
| UGd | 1,764 | 872 | 2,262,967 | $ 27,311,810 | $ 28,181,226 | $ 28,248,553 | $ 444,634 | $ 28,693,186 |
| St Lgt | 5,577 | 81 | - | $ 9,373,700 | $ 9,804,724 | $ 9,695,200 | $ 250,450 | $ 9,945,650 |
| Sen Lgt | 18,765 | 11 | - | $ 2,551,198 | $ 5,390,869 | $ 2,638,699 | $ 2,767,677 | $ 5,406,376 |
| USL | 5,832 | 33 | - | $ 3,455,713 | $ 3,532,656 | $ 3,574,238 | $ 87,996 | $ 3,662,234 |
| DGen | 1,662 | 32 | 219,198 | $ 6,359,723 | $ 6,210,497 | $ 6,577,849 | $ 78,386 | $ 6,656,235 |
| ST | 924 | 15,011 | 30,684,065 | $ 64,049,946 | $ 65,632,537 | $ 66,246,736 | $ 1,273,025 | $ 67,519,762 |
| AUR | 15,622 | 119 | - | $ 5,882,627 | $ 6,118,696 | $ 6,084,390 | $ 264,868 | $ 6,349,258 |
| AUGe | 1,404 | 42 | - | $ 1,089,709 | $ 1,113,149 | $ 1,127,084 | $ 33,621 | $ 1,160,706 |
| AUGd | 208 | 119 | 334,687 | $ 1,216,468 | $ 1,256,764 | $ 1,258,190 | $ 41,839 | $ 1,300,029 |
| AR | 39,401 | 332 | - | $ 18,018,778 | $ 18,648,526 | $ 18,636,787 | $ 727,352 | $ 19,364,139 |
| AGSe | 4,203 | 115 | - | $ 4,121,195 | $ 4,258,365 | $ 4,262,544 | $ 115,579 | $ 4,378,124 |
| AGSd | 308 | 227 | 635,376 | $ 3,411,715 | $ 3,520,853 | $ 3,528,731 | $ 91,884 | $ 3,620,614 |
| **TOTAL** | **1,434,135** | **33,460** | **41,023,220** | **1,686,305,528** | **1,729,028,099** | **1,744,142,576** | **44,088,426** | **1,788,231,001** |

The columns D to J of the table below are printed under the heading: **Derivation of 2025 Fixed Charge for Non-Residential Classes**

| | Current (2024) Fixed Charge for Non-Residential Classes ($/month) | Fixed Charge Ceiling for Non-Residential Classes from CAM ($/month) | Is Current Fixed Charge higher than CAM Ceiling? | Current (2024) F/V Split for Non-Residential Classes | 2025 Revenue from Fixed Charge using Current F/V Split | 2025 Fixed Charge Using Current F/V Split ($/month)* | 2025 Base Fixed Charge for Non-Residential Classes ($/month) | Base Fixed Charge ($/month) | Revenue from Fixed Charge | Revenue from Volumetric Charge | Base Volumetric Charge ($/kWh) | Base Volumetric Charge ($/kW) | CSTA Rate Adders ($/kW) | Hopper Foundry Rate Adder ($/kW) | Total Volumetric Charge ($/kW) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | (D) | (E) | (F) If D > E then "Yes" else "No" | (G) | (H) = A x G | (I) = H / Number of Customers / 12 | (J) If F="Yes" then fixed charge = Min(D, I), else fixed charge = I | (K): UR, R1, R2, AUR, and AR = 100% Fixed; Seasonal-R2 = See table below; Non-Residential Classes = J | (L) = K x Number of Customers x 12 | (M) = A - L | (N) = M/kWh | (O) = M/kW | (P) | (Q) | (R) = O+P+Q |
| UR | | | | | | | | $ 39.30 | $ 118,891,425 | $ - | | | | | |
| R1 | | | | | | | | $ 67.08 | $ 445,565,725 | $ - | | | | | |
| R2 | | | | | | | | $ 135.93 | $ 557,002,623 | $ 52,168,720 | $ 0.0110 | | | | |
| Seasonal-R2 | | | | | | | | $ 80.53 | $ 75,838,617 | | | | | | |
| GSe | 31.33 | $ 21.53 | Yes | 20% | $ 33,917,811 | $ 31.80 | $ 31.33 | $ 31.33 | $ 33,419,421 | $ 140,161,982 | $ 0.0724 | | | | |
| GSd | 100.82 | $ 58.07 | Yes | 5% | $ 6,648,826 | $ 101.86 | $ 100.82 | $ 100.82 | $ 6,580,694 | $ 138,430,826 | | $ 20.1005 | $ 0.0973 | $ 0.0138 | $ 20.2116 |
| UGe | 24.39 | $ 13.35 | Yes | 23% | $ 5,541,735 | $ 24.80 | $ 24.39 | $ 24.39 | $ 5,449,833 | $ 18,753,710 | $ 0.0349 | | | | |
| UGd | 92.16 | $ 52.73 | Yes | 7% | $ 1,974,610 | $ 93.29 | $ 92.16 | $ 92.16 | $ 1,950,673 | $ 26,297,880 | | $ 11.6210 | $ 0.1313 | | $ 11.7523 |
| St Lgt | 3.09 | $ 15.27 | No | 2% | $ 208,198 | $ 3.11 | $ 3.11 | $ 3.11 | $ 208,198 | $ 9,487,002 | $ 0.1166 | | | | |
| Sen Lgt | 3.12 | $ 16.70 | No | 27% | $ 714,531 | $ 3.17 | $ 3.17 | $ 3.17 | $ 714,531 | $ 1,924,168 | $ 0.1798 | | | | |
| USL | 36.72 | $ 35.83 | Yes | 74% | $ 2,648,227 | $ 37.84 | $ 36.72 | $ 36.72 | $ 2,569,973 | $ 1,004,265 | $ 0.0308 | | | | |
| DGen | 190.79 | $ 143.65 | Yes | 59% | $ 3,869,415 | $ 194.04 | $ 190.79 | $ 190.79 | $ 3,804,668 | $ 2,773,181 | | $ 12.6515 | $ 0.4897 | | $ 13.1412 |
| ST | 1,055.65 | $ 59.88 | Yes | 18% | $ 11,955,929 | $ 1,078.28 | $ 1,055.65 | N/A** | $ 11,705,047 | $ 54,541,689 | | N/A** | | | N/A** |
| AUR | | | | | | | | $ 32.46 | $ 6,084,390 | $ - | | | | | |
| AUGe | 25.59 | $ 7.04 | Yes | 40% | $ 446,165 | $ 26.48 | $ 25.59 | $ 25.59 | $ 431,167 | $ 695,917 | $ 0.0167 | | | | |
| AUGd | 146.47 | $ 33.25 | Yes | 30% | $ 377,457 | $ 151.59 | $ 146.47 | $ 146.47 | $ 364,710 | $ 893,480 | | $ 2.6696 | $ 0.3157 | | $ 2.9853 |
| AR | | | | | | | | $ 39.42 | $ 18,636,787 | $ - | | | | | |
| AGSe | 38.38 | $ 5.04 | Yes | 47% | $ 1,996,152 | $ 39.58 | $ 38.38 | $ 38.38 | $ 1,935,794 | $ 2,326,750 | $ 0.0202 | | | | |
| AGSd | 170.26 | $ 53.25 | Yes | 18% | $ 642,769 | $ 173.70 | $ 170.26 | $ 170.26 | $ 630,050 | $ 2,898,680 | | $ 4.5621 | $ 0.2540 | | $ 4.8161 |
| **TOTAL** | | | | | | | | | **$ 1,291,784,327** | **$ 452,358,249** | | | | | |

**Derivation of 2025 Mitigated Fixed Charge for Seasonal Customers Moving to R2 Class**

| **Current (2024) Fixed Charge for Seasonal-R2 Customers ($/month)** (A1) | **All-Fixed Distribution Charge for R2 Class ($/month)** (B1 = $A_{R2}$/Number of Customers($_{R2+Seasonal-R2}$)/12) | **Phase-in Period (in years)** (C1) | **Annual Increase in Seasonal-R2 Fixed Charge ($)** (D1 = (B1-A1)/C1) | **2025 Fixed Charge for Seasonal Customers Moving to R2 Class ($/month)** (E1=A1+D1) |
|---|---|---|---|---|
| $ 72.62 | $ 135.93 | 8 | $ 7.91 | $ 80.53 |

| | |
|---|---|
| **Total Revenue from Rates (L+M)** | **$ 1,744,142,576** |
| **Miscellaneous Revenue (B)** | **$ 44,088,426** |
| **Total Revenue Reqquirement (L+M+B)** | **$ 1,788,231,001** |

* GWh shown for R2 class includes consumption associaed with Seasonal customers moving to the R2 class.

** Final ST rates are provided in Schedule 4.1.

**2025 Adjustments (from 2024 Revenue Requirement) by Rate Class**

| | 2024 | 2025 | % (X) |
|---|---|---|---|
| Revenue Requirement*** | $ 1,686,305,528 | $ 1,744,142,576 | 103.43% |
| Alloc Cost | $ 1,729,028,099 | $ 1,788,231,001 | 103.42% |
| Misc Revenue | $ 43,888,426 | $ 44,088,426 | 100.46% |

*** 2024: Revenue with 2024 rates and 2025 charge determinants
2025: 2025 Revenue before rate design adjustments

## 2026 Rate Design

| | Number of Customers | GWh* | kWs | Revenue - with 2025 Rates and 2026 Charge Determinants (Y) | 2025 Revenue (Z) | 2026 Rates Revenue Requirement (A) = $Y*X_{RevReq}$ | 2026 Misc Rev (B) = $B_{2025}*X_{MiscRev}$ | 2026 Total Revenue (C) = A+B |
|---|---|---|---|---|---|---|---|---|
| UR | 254,909 | 2,040 | - | $ 120,214,858 | $ 123,329,561 | $ 125,638,735 | $ 4,408,466 | $ 130,047,200 |
| R1 | 557,928 | 5,083 | - | $ 449,109,381 | $ 457,727,075 | $ 469,372,384 | $ 12,080,047 | $ 481,452,431 |
| R2 | 343,409 | 4,708 | - | $ 687,677,449 | $ 699,918,402 | $ 718,704,212 | $ 14,808,773 | $ 733,512,985 |
| Seasonal-R2 | 78,325 | | | | | | | |
| GSe | 88,970 | 1,914 | - | $ 171,949,325 | $ 177,237,797 | $ 179,707,368 | $ 3,631,949 | $ 183,339,317 |
| GSd | 5,487 | 2,138 | 6,852,769 | $ 144,382,554 | $ 147,160,923 | $ 150,896,834 | $ 2,135,033 | $ 153,031,867 |
| UGe | 18,720 | 535 | - | $ 24,122,445 | $ 24,800,931 | $ 25,210,806 | $ 593,395 | $ 25,804,201 |
| UGd | 1,775 | 868 | 2,249,148 | $ 28,100,080 | $ 28,693,186 | $ 29,367,904 | $ 441,661 | $ 29,809,566 |
| St Lgt | 5,615 | 81 | - | $ 9,606,292 | $ 9,945,650 | $ 10,039,711 | $ 248,775 | $ 10,288,486 |
| Sen Lgt | 18,439 | 10 | - | $ 2,572,071 | $ 5,406,376 | $ 2,688,119 | $ 2,749,174 | $ 5,437,293 |
| USL | 5,869 | 33 | - | $ 3,593,441 | $ 3,662,234 | $ 3,755,570 | $ 87,408 | $ 3,842,978 |
| DGen | 1,748 | 32 | 224,090 | $ 6,836,595 | $ 6,656,235 | $ 7,145,049 | $ 77,862 | $ 7,222,911 |
| ST | 931 | 15,004 | 30,671,163 | $ 66,312,477 | $ 67,519,762 | $ 69,304,376 | $ 1,264,515 | $ 70,568,891 |
| AUR | 15,690 | 120 | - | $ 6,111,385 | $ 6,349,258 | $ 6,387,120 | $ 263,097 | $ 6,650,217 |
| AUGe | 1,416 | 42 | - | $ 1,139,276 | $ 1,160,706 | $ 1,190,678 | $ 33,396 | $ 1,224,075 |
| AUGd | 208 | 119 | 334,742 | $ 1,258,512 | $ 1,300,029 | $ 1,315,294 | $ 41,559 | $ 1,356,853 |
| AR | 39,591 | 330 | - | $ 18,727,922 | $ 19,364,139 | $ 19,572,892 | $ 722,489 | $ 20,295,381 |
| AGSe | 4,193 | 114 | - | $ 4,235,257 | $ 4,378,124 | $ 4,426,345 | $ 114,807 | $ 4,541,151 |
| AGSd | 311 | 225 | 629,258 | $ 3,506,085 | $ 3,620,614 | $ 3,664,273 | $ 91,270 | $ 3,755,543 |
| **TOTAL** | **1,443,532** | **33,396** | **40,961,169** | **1,749,455,406** | **1,788,231,001** | **1,828,387,671** | **43,793,675** | **1,872,181,345** |

| | Derivation of 2026 Fixed Charge for Non-Residential Classes | | | | | | |
|---|---|---|---|---|---|---|---|
| | Current (2025) Fixed Charge for Non-Residential Classes ($/month) (D) | Fixed Charge Ceiling for Non-Residential Classes from CAM ($/month) (E) | Is Current Fixed Charge higher than CAM Ceiling? (F) If D > E then "Yes" else "No" | Current (2025) F/V Split for Non-Residential Classes (G) | 2026 Revenue from Fixed Charge using Current F/V Split (H) = A x G | 2026 Fixed Charge Using Current F/V Split ($/month)* (I) = H / Number of Customers / 12 | 2026 Base Fixed Charge for Non-Residential Classes ($/month) (J) If F="Yes" then fixed charge = Min(D, I), else fixed charge = I |
| UR | | | | | | | |
| R1 | | | | | | | |
| R2 | | | | | | | |
| Seasonal-R2 | | | | | | | |
| GSe | $ 31.33 | $ 21.53 | Yes | 19% | $ 34,598,846 | $ 32.41 | $ 31.33 |
| GSd | $ 100.82 | $ 58.07 | Yes | 5% | $ 6,847,773 | $ 104.00 | $ 100.82 |
| UGe | $ 24.39 | $ 13.35 | Yes | 23% | $ 5,676,635 | $ 25.27 | $ 24.39 |
| UGd | $ 92.16 | $ 52.73 | Yes | 7% | $ 2,027,968 | $ 95.22 | $ 92.16 |
| St Lgt | $ 3.11 | $ 15.27 | No | 2% | $ 215,597 | $ 3.20 | $ 3.20 |
| Sen Lgt | $ 3.17 | $ 16.70 | No | 27% | $ 727,913 | $ 3.29 | $ 3.29 |
| USL | $ 36.72 | $ 35.83 | Yes | 72% | $ 2,700,356 | $ 38.34 | $ 36.72 |
| DGen | $ 190.79 | $ 143.65 | Yes | 58% | $ 4,132,740 | $ 197.05 | $ 190.79 |
| ST | $ 1,055.65 | $ 59.88 | Yes | 18% | $ 12,245,298 | $ 1,096.07 | $ 1,055.65 |
| AUR | | | | 0% | | $ - | |
| AUGe | $ 25.59 | $ 7.04 | Yes | 38% | $ 455,495 | $ 26.81 | $ 25.59 |
| AUGd | $ 146.47 | $ 33.25 | Yes | 29% | $ 381,263 | $ 153.04 | $ 146.47 |
| AR | | | | 0% | | $ - | |
| AGSe | $ 38.38 | $ 5.04 | Yes | 45% | $ 2,010,182 | $ 39.95 | $ 38.38 |
| AGSd | $ 170.26 | $ 53.25 | Yes | 18% | $ 654,251 | $ 175.33 | $ 170.26 |

| | Base Fixed Charge ($/month) (K): UR, R1, R2, AUR, and AR = 100% Fixed; Seasonal-R2 = See table below; Non-Residential Classes = J | Revenue from Fixed Charge (L) = K x Number of Customers x 12 | Revenue from Volumetric Charge (M) = A - L | Base Volumetric Charge ($/kWh) (N) = M/kWh | Base Volumetric Charge ($/kW) (O) = M/kW | CSTA Rate Adders ($/kW) (P) | Hopper Foundry Rate Adder ($/kW) (Q) | Total Volumetric Charge ($/kW) (R) = O+P+Q |
|---|---|---|---|---|---|---|---|---|
| UR | $ 41.07 | $ 125,638,735 | $ - | | | | | |
| R1 | $ 70.11 | $ 469,372,384 | $ - | | | | | |
| R2 | $ 142.01 | $ 585,226,149 | $ 49,529,977 | $ 0.0105 | | | | |
| Seasonal-R2 | $ 89.32 | $ 83,948,086 | $ - | | | | | |
| GSe | $ 31.33 | $ 33,449,005 | $ 146,258,363 | $ 0.0764 | | | | |
| GSd | $ 100.82 | $ 6,638,308 | $ 144,258,526 | | $ 21.0511 | $ 0.0973 | $ 0.0145 | $ 21.1629 |
| UGe | $ 24.39 | $ 5,479,023 | $ 19,731,784 | $ 0.0369 | | | | |
| UGd | $ 92.16 | $ 1,962,790 | $ 27,405,114 | | $ 12.1847 | $ 0.1313 | | $ 12.3160 |
| St Lgt | $ 3.20 | $ 215,597 | $ 9,824,114 | $ 0.1219 | | | | |
| Sen Lgt | $ 3.29 | $ 727,913 | $ 1,960,206 | $ 0.1884 | | | | |
| USL | $ 36.72 | $ 2,586,293 | $ 1,169,277 | $ 0.0357 | | | | |
| DGen | $ 190.79 | $ 4,001,529 | $ 3,143,520 | | $ 14.0280 | $ 0.4897 | | $ 14.5177 |
| ST | N/A** | $ 11,793,722 | $ 57,510,654 | | N/A * | | | N/A * |
| AUR | $ 33.92 | $ 6,387,120 | $ - | | | | | |
| AUGe | $ 25.59 | $ 434,763 | $ 755,916 | $ 0.0179 | | | | |
| AUGd | $ 146.47 | $ 364,886 | $ 950,408 | | $ 2.8392 | $ 0.3157 | | $ 3.1549 |
| AR | $ 41.20 | $ 19,572,892 | $ - | | | | | |
| AGSe | $ 38.38 | $ 1,931,212 | $ 2,495,132 | $ 0.0218 | | | | |
| AGSd | $ 170.26 | $ 635,319 | $ 3,028,954 | | $ 4.8135 | $ 0.2540 | | $ 5.0675 |
| **TOTAL** | | **$ 1,360,365,726** | **$ 468,021,945** | | | | | |

**Derivation of 2026 Mitigated Fixed Charge for Seasonal Customers Moving to R2 Class**

| **Current (2025) Fixed Charge for Seasonal-R2 Customers ($/month)** (A1) | **All-Fixed Distribution Charge for R2 Class ($/month)** (B1 = $A_{R2}$/Number of Customers$_{(R2+Seasonal-R2)}$/12) | **Phase-in Period (in years)** (C1) | **Annual Increase in Seasonal-R2 Fixed Charge ($)** (D1 = (B1-A1)/C1) | **2026 Fixed Charge for Seasonal Customers Moving to R2 Class ($/month)** (E1=A1+D1) |
|---|---|---|---|---|
| $ 80.53 | $ 142.01 | 7 | $ 8.78 | $ 89.32 |

| | |
|---|---|
| **Total Revenue from Rates (L+M)** | **$ 1,828,387,671** |
| **Miscellaneous Revenue (B)** | **$ 43,793,675** |
| **Total Revenue Reqquirement (L+M+B)** | **$ 1,872,181,345** |

* GWh shown for R2 class includes consumption associaed with Seasonal customers moving to the R2 class.

** Final ST rates are provided in Schedule 4.1.

**2026 Adjustments (from 2025 Revenue Requirement) by Rate Class**

| | 2025 | 2026 | % (X) |
|---|---|---|---|
| Revenue Requirement*** | $ 1,749,455,406 | $ 1,828,387,671 | 104.51% |
| Alloc Cost | $ 1,788,231,001 | $ 1,872,181,345 | 104.69% |
| Misc Revenue | $ 44,088,426 | $ 43,793,675 | 99.33% |

*** 2025: Revenue with 2025 rates and 2026 charge determinants
2026: 2026 Revenue before rate design adjustments

## 2027 Rate Design

| | Number of Customers | GWh* | kWs | Revenue - with 2026 Rates and 2027 Charge Determinants | 2026 Revenue | 2027 Rates Revenue Requirement | 2027 Misc Rev | 2027 Total Revenue | Derivation of 2027 Fixed Charge for Non-Residential Classes: Current (2026) Fixed Charge for Non-Residential Classes ($/month) | Fixed Charge Ceiling for Non-Residential Classes from CAM ($/month) | Is Current Fixed Charge higher than CAM Ceiling? | Current (2026) F/V Split for Non-Residential Classes | 2027 Revenue from Fixed Charge using Current F/V Split | 2027 Fixed Charge Using Current F/V Split ($/month)* | 2027 Base Fixed Charge for Non-Residential Classes ($/month) | Base Fixed Charge ($/month) | Revenue from Fixed Charge | Revenue from Volumetric Charge | Base Volumetric Charge ($/kWh) | Base Volumetric Charge ($/kW) | CSTA Rate Adders ($/kW) | Hopper Foundry Rate Adder ($/kW) | Total Volumetric Charge ($/kW) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | (Y) | (Z) | (A) = $Y^*X_{RevReq}$ | (B) = $B_{2026}{}^*X_{MiscRev}$ | (C) = A+B | (D) | (E) | (F) If D > E then "Yes" else "No" | (G) | (H) = A x G | (I) = H / Number of Customers / 12 | (J) If F="Yes" then fixed charge = Min(D, I), else fixed charge = I | (K): UR, R1, R2, AUR, and AR = 100% Fixed; Seasonal-R2 = See table below; Non-Residential Classes = J | (L) = K x Number of Customers x 12 | (N) = M/kWh | (O) = M/kW | (P) | (Q) | (R) = O+P+Q | |
| UR | 257,709 | 2,063 | - | $ 127,009,133 | $ 130,047,200 | $ 131,391,726 | $ 4,448,731 | $ 135,840,457 | | | | | | | | $ 42.49 | $ 131,391,726 | $ - | | | | | |
| R1 | 562,310 | 5,129 | - | $ 473,082,452 | $ 481,452,431 | $ 489,406,693 | $ 12,190,383 | $ 501,597,076 | | | | | | | | $ 72.53 | $ 489,406,693 | $ - | | | | | |
| R2 | 345,305 | 4,711 | - | $ 721,783,000 | $ 733,512,985 | $ 746,688,933 | $ 14,944,032 | $ 761,632,965 | | | | | | | | $ 146.94 | $ 608,864,939 | $ 45,040,048 | $ 0.0096 | | | | |
| Seasonal-R2 | 78,164 | | | | | | | | | | | | | | | $ 98.92 | $ 92,783,947 | $ - | | | | | |
| GSe | 89,067 | 1,905 | - | $ 179,036,585 | $ 183,339,317 | $ 185,214,443 | $ 3,665,122 | $ 188,879,566 | $ 31.33 | $ 21.53 | Yes | 19% | $ 34,474,040 | $ 32.25 | $ 31.33 | $ 31.33 | $ 33,485,678 | $ 151,728,765 | $ 0.0797 | | | | |
| GSd | 5,536 | 2,143 | 6,868,965 | $ 151,296,787 | $ 153,031,867 | $ 156,517,453 | $ 2,154,534 | $ 158,671,987 | $ 100.82 | $ 58.07 | Yes | 4% | $ 6,885,572 | $ 103.65 | $ 100.82 | $ 100.82 | $ 6,697,335 | $ 149,820,118 | | $ 21.8112 | $ 0.0973 | $ 0.0150 | $ 21.9235 |
| UGe | 18,824 | 535 | - | $ 25,265,500 | $ 25,804,201 | $ 26,137,314 | $ 598,815 | $ 26,736,129 | $ 24.39 | $ 13.35 | Yes | 22% | $ 5,680,379 | $ 25.15 | $ 24.39 | $ 24.39 | $ 5,509,267 | $ 20,628,047 | $ 0.0385 | | | | |
| UGd | 1,786 | 871 | 2,251,682 | $ 29,411,305 | $ 29,809,566 | $ 30,426,175 | $ 445,695 | $ 30,871,871 | $ 92.16 | $ 52.73 | Yes | 7% | $ 2,033,519 | $ 94.88 | $ 92.16 | $ 92.16 | $ 1,975,321 | $ 28,450,854 | | $ 12.6354 | $ 0.1313 | | $ 12.7667 |
| St Lgt | 5,654 | 80 | - | $ 10,012,370 | $ 10,288,486 | $ 10,357,858 | $ 251,048 | $ 10,608,905 | $ 3.20 | $ 15.27 | No | 2% | $ 222,429 | $ 3.28 | $ 3.28 | $ 3.28 | $ 222,429 | $ 10,135,429 | $ 0.1261 | | | | |
| Sen Lgt | 18,117 | 10 | - | $ 2,634,169 | $ 5,437,293 | $ 2,725,064 | $ 2,774,284 | $ 5,499,348 | $ 3.29 | $ 16.70 | No | 27% | $ 737,917 | $ 3.39 | $ 3.39 | $ 3.39 | $ 737,917 | $ 1,987,146 | $ 0.1951 | | | | |
| USL | 5,906 | 33 | - | $ 3,783,022 | $ 3,842,978 | $ 3,913,559 | $ 88,206 | $ 4,001,765 | $ 36.72 | $ 35.83 | Yes | 69% | $ 2,695,093 | $ 38.03 | $ 36.72 | $ 36.72 | $ 2,602,400 | $ 1,311,159 | $ 0.0397 | | | | |
| DGen | 1,834 | 33 | 230,562 | $ 7,432,322 | $ 7,222,911 | $ 7,688,782 | $ 78,573 | $ 7,767,355 | $ 190.79 | $ 143.65 | Yes | 56% | $ 4,306,043 | $ 195.70 | $ 190.79 | $ 190.79 | $ 4,198,003 | $ 3,490,779 | | $ 15.1403 | $ 0.4897 | | $ 15.6300 |
| ST | 938 | 15,090 | 30,845,323 | $ 69,719,614 | $ 70,568,891 | $ 72,125,368 | $ 1,276,064 | $ 73,401,432 | $ 1,055.65 | $ 59.88 | Yes | 17% | $ 12,273,778 | $ 1,090.42 | $ 1,055.65 | N/A** | $ 11,882,396 | $ 60,242,971 | | N/A** | | | N/A** |
| AUR | 15,756 | 121 | - | $ 6,413,329 | $ 6,650,217 | $ 6,634,628 | $ 265,500 | $ 6,900,128 | | | | | | | | $ 35.09 | $ 6,634,628 | $ - | | | | | |
| AUGe | 1,427 | 43 | - | $ 1,205,529 | $ 1,224,075 | $ 1,247,127 | $ 33,702 | $ 1,280,828 | $ 25.59 | $ 7.04 | Yes | 37% | $ 455,374 | $ 26.59 | $ 25.59 | $ 25.59 | $ 438,179 | $ 808,947 | $ 0.0188 | | | | |
| AUGd | 208 | 119 | 334,386 | $ 1,314,458 | $ 1,356,853 | $ 1,359,815 | $ 41,938 | $ 1,401,753 | $ 146.47 | $ 33.25 | Yes | 28% | $ 377,237 | $ 151.35 | $ 146.47 | $ 146.47 | $ 365,062 | $ 994,753 | | $ 2.9749 | $ 0.3157 | | $ 3.2906 |
| AR | 39,777 | 327 | - | $ 19,665,972 | $ 20,295,381 | $ 20,344,568 | $ 729,088 | $ 21,073,656 | | | | | | | | $ 42.62 | $ 20,344,568 | $ - | | | | | |
| AGSe | 4,183 | 113 | - | $ 4,392,905 | $ 4,541,151 | $ 4,544,487 | $ 115,855 | $ 4,660,343 | $ 38.38 | $ 5.04 | Yes | 44% | $ 1,982,758 | $ 39.50 | $ 38.38 | $ 38.38 | $ 1,926,569 | $ 2,617,918 | $ 0.0232 | | | | |
| AGSd | 313 | 223 | 622,315 | $ 3,636,010 | $ 3,755,543 | $ 3,761,475 | $ 92,103 | $ 3,853,578 | $ 170.26 | $ 53.25 | Yes | 17% | $ 652,172 | $ 173.37 | $ 170.26 | $ 170.26 | $ 640,477 | $ 3,120,998 | | $ 5.0151 | $ 0.2540 | | $ 5.2691 |
| **TOTAL** | **1,452,813** | **33,548** | **41,153,231** | **1,837,094,461** | **1,872,181,345** | **1,900,485,467** | **44,193,675** | **1,944,679,142** | | | | | | | | | **$ 1,420,107,534** | **$ 480,377,934** | | | | | |

**Derivation of 2027 Mitigated Fixed Charge for Seasonal Customers Moving to R2 Class**

| **Current (2026) Fixed Charge for Seasonal-R2 Customers ($/month)** (A1) | **All-Fixed Distribution Charge for R2 Class ($/month)** (B1 = $A_{R2}$/Number of Customers($_{R2+Seasonal-R2}$)/12) | **Phase-in Period (in years)** (C1) | **Annual Increase in Seasonal-R2 Fixed Charge ($)** (D1 = (B1-A1)/C1) | **2027 Fixed Charge for Seasonal Customers Moving to R2 Class ($/month)** (E1=A1+D1) |
|---|---|---|---|---|
| $ 89.32 | $ 146.94 | 6 | $ 9.60 | $ 98.92 |

| | |
|---|---|
| **Total Revenue from Rates (L+M)** | **$ 1,900,485,467** |
| **Miscellaneous Revenue (B)** | **$ 44,193,675** |
| **Total Revenue Requirement (L+M+B)** | **$ 1,944,679,142** |

* GWh shown for R2 class includes consumption associated with Seasonal customers moving to the R2 class.

** Final ST rates are provided in Schedule 4.1.

**2027 Adjustments (from 2026 Revenue Requirement) by Rate Class**

| | 2026 | 2027 | % (X) |
|---|---|---|---|
| Revenue Requirement*** | $ 1,837,094,461 | $ 1,900,485,467 | 103.45% |
| Alloc Cost | $ 1,872,181,345 | $ 1,944,679,142 | 103.87% |
| Misc Revenue | $ 43,793,675 | $ 44,193,675 | 100.91% |

*** 2026: Revenue with 2026 rates and 2027 charge determinants
2027: 2027 Revenue before rate design adjustments

**Derivation of ST Common Line Charge**

| | 2023 | | | | 2024 | | | | 2025 | | | | 2026 | | | | 2027 | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Minus | Billing Quantity (Annual) | Rates | | Revenue Generated (Annual) | Billing Quantity (Annual) | Rates | | Revenue Generated (Annual) | Billing Quantity (Annual) | Rates | | Revenue Generated (Annual) | Billing Quantity (Annual) | Rates | | Revenue Generated (Annual) | Billing Quantity (Annual) | Rates | | Revenue Generated (Annual) |
| HVDS-high cost allocation | 1,128,331 | 2.9907 | $/kW | $ 3,374,499 | 1,132,549 | 2.9907 | $/kW | $ 3,387,115 | 1,123,875 | 2.9907 | $/kW | $ 3,361,172 | 1,123,402 | 2.9907 | $/kW | $ 3,359,759 | 1,129,781 | 2.9907 | $/kW | $ 3,378,837 |
| HVDS-low cost allocation | 65,965 | 4.8501 | $/kW | $ 319,935 | 66,211 | 4.9246 | $/kW | $ 326,064 | 65,704 | 4.9955 | $/kW | $ 328,225 | 65,676 | 5.0870 | $/kW | $ 334,096 | 66,049 | 5.1588 | $/kW | $ 340,736 |
| LVDS-low cost allocation | 681,526 | 1.8594 | $/kW | $ 1,267,229 | 684,074 | 1.9339 | $/kW | $ 1,322,930 | 678,834 | 2.0048 | $/kW | $ 1,360,926 | 678,549 | 2.0963 | $/kW | $ 1,422,441 | 682,402 | 2.1681 | $/kW | $ 1,479,515 |
| Specific ST lines | 723 | 595.4935 | $/kM | $ 430,692 | 723 | 621.6574 | $/kM | $ 449,615 | 723 | 639.5328 | $/kM | $ 462,543 | 723 | 668.4135 | $/kM | $ 483,431 | 723 | 695.2427 | $/kM | $ 502,836 |
| Plus: | | | | $ - | | | | $ - | | | | $ - | | | | | | | | |
| Service Charge (per Delivery Point) | 10,920 | 790.43 | $ | $ 8,631,496 | 11,004 | 790.43 | $ | $ 8,697,892 | 11,088 | 790.43 | $ | $ 8,764,288 | 11,172 | 790.43 | $ | $ 8,830,684 | 11,256 | 790.43 | $ | $ 8,897,080 |
| Meter Charge (for Hydro One ownership per Meter Point) | 7,296 | 396.96 | $ | $ 2,896,220 | 7,352 | 396.96 | $ | $ 2,918,628 | 7,409 | 396.96 | $ | $ 2,940,908 | 7,465 | 396.96 | $ | $ 2,963,187 | 7,521 | 396.96 | $ | $ 2,985,467 |
| Total revenue generated through other delivery charges: | | | | $ 16,920,070 | | | | $ 17,102,243 | | | | $ 17,218,062 | | | | $ 17,393,599 | | | | $ 17,584,470 |
| Revenue to be recovered through ST rates | | | | $ 61,611,805 | | | | $ 64,365,287 | | | | $ 66,246,736 | | | | $ 69,304,376 | | | | $ 72,125,368 |
| ST Common Line Revenue Requirement (Annual $) | | | | $ 44,691,735 | | | | $ 47,263,044 | | | | $ 49,028,674 | | | | $ 51,910,777 | | | | $ 54,540,898 |
| ST Common Line Charge Determinant (Annual kM) | 30,260,193 | | | | 30,373,324 | | | | 30,140,687 | | | | 30,128,014 | | | | 30,299,090 | | | |
| **ST Common Line Charge (Monthly $/kW)** | | **$ 1.4769** | | | | **$ 1.5561** | | | | **$ 1.6267** | | | | **$ 1.7230** | | | | **$ 1.8001** | | |

**Derivation of Facility Charge for connection to Low Voltage Distribution Station (LVDS Low)**

| USoA | Account | 2023 | | 2024 | 2025 | 2025 | 2027 |
|---|---|---|---|---|---|---|---|
| | Proportion of Total Forecast Costs associated with ST share of LVDS-low stations | 1.52% | | | | | |
| **USoA** | **Account** | Allocation to ST rate class (2023 CAM O4 Sheet) | Proportion of allocation to ST rate class associated with LVDS-low | | | | |
| 5005 | Operation Supervision and Engineering | $ 120,596 | $ 1,838 | | | | |
| 5012 | Station Buildings and Fixtures Expense [exclude - no "bldgs" at LVDSs] | $ - | $ - | | | | |
| 5016 | Distribution Station Equipment - Operation Labour | $ 98,257 | $ 98,257 | | | | |
| 5017 | Distribution Station Equipment - Operation Supplies and Expenses | $ 29,222 | $ 29,222 | | | | |
| 5105 | Maintenance Supervision and Engineering | $ 474,396 | $ 7,229 | | | | |
| 5110 | Maintenance of Buildings and Fixtures - Distribution Stations | $ 106,675 | $ 106,675 | | | | |
| 5114 | Maintenance of Distribution Station Equipment | $ 233,993 | $ 233,993 | | | | |
| 5405 to 5680 | 25 General Admin. Acc'ts (12 non-zero) | $ 5,312,447 | $ 80,949 | | | | |
| | **Other ("NIDIT") "expenses"** | | | | | | |
| 3046 | Net Inc (Balance Transferred From Income) | $ 15,663,750 | $ 238,679 | | | | |
| 5705 | Amortization Expense - Property, Plant, and Equipment | $ 17,596,988 | $ 268,138 | | | | |
| 6005 | Interest on Long Term Debt | $ 10,992,801 | $ 167,505 | | | | |
| 6105 | Taxes Other Than Income Taxes | $ 305,419 | $ 4,654 | | | | |
| 6110 | Income Taxes | $ 1,975,153 | $ 30,097 | | | | |
| | **Change in Service Revenue Requirement allocated to the ST rate class** | | | 4.4% | 2.9% | 4.5% | 4.0% |
| | **Total LVDS Low Revenue Requirement (Annual $)** | | **$ 1,267,237** | **$ 1,322,915** | **$ 1,360,954** | **$ 1,422,414** | **$ 1,479,508** |
| | **Total LVDS Low Charge Determinant (Annual kW)** | | **681,526** | **684,074** | **678,834** | **678,549** | **682,402** |
| | **LVDS Low Rate (Monthly, $/kW)** | | 1.8594 | 1.9339 | 2.0048 | 2.0963 | 2.1681 |

**Note: USofA 5016, 5017 & 5114 are wholly recovered by the LVDS Low tariff

**Derivation of Facility Charge for connection to Specific ST Lines**

| | | 2023 Total | 2023 Assigned to Lines |
|---|---|---|---|
| | Costs: di Lines - 50kV to 750V | $ 203,846,607 | $ 203,846,607 |
| | Costs: di General + di Remainder | $ 87,201,657 | |
| | Costs: cu group (excluding customer premise costs) | $ 97,614,772 | |
| | Proportion of Total (di+cu) Costs allocated to ST Lines | | 52.4% |
| | **Expenses** | | |
| **di** | Distribution Costs (di) | $ 291,048,265 | $ 203,846,607 |
| **cu** | Customer Related Costs (cu) | $ 136,745,875 | |
| **ad** | General and Administration (ad) | $ 178,401,000 | $ 93,568,040 |
| **dep** | Depreciation and Amortization (dep) | $ 461,417,513 | $ 242,004,991 |
| **INPUT** | PILs (INPUT) | $ 39,794,572 | $ 20,871,520 |
| **INT** | Interest | $ 221,478,424 | $ 116,161,356 |
| | **Direct Allocation** | $ 11,805,407 | $ - |
| **NI** | Allocated Net Income (NI) | $ 315,586,769 | $ 165,519,450 |
| | **Total Revenue Requirement (includes NI)** | $ 1,656,277,824 | $ 841,971,965 |

| | 2023 | 2024 | 2025 | 2026 | 2027 |
|---|---|---|---|---|---|
| **Change in Service Revenue Requirement allocated to the ST rate class** | | 4.4% | 2.9% | 4.5% | 4.0% |
| <u>**Specific Line Rates Calculation**</u> | | | | | |
| Annual costs associated with all HON "50 kV to 750 V" Line Assets | $ 841,971,965 | $ 878,965,231 | $ 904,239,346 | $ 945,073,950 | $ 983,007,956 |
| Total Length 44 kV to 13.8 kV inclusive (2020 Actual, kM) | 30,016 | | | | |
| Total Length 12.5 to 4.16 kV inclusive (2020 Actual, weighted kM) | 87,809 | | | | |
| Total km of 50kV-to-4.16kV line (Actual 2020, kM) | 117,826 | 117,826 | 117,826 | 117,826 | 117,826 |
| **ST Specific Line Rate (Monthly, per kM)** | $ 595.4935 | $ 621.6574 | $ 639.5328 | $ 668.4135 | $ 695.2427 |

Ontario Energy Board

# Revenue Requirement Workform (RRWF) for 2023 Filers

New Rate Design Policy For Residential Customers
Please complete the following tables.

**Year-Round Medium Density Residential (R1) - Proposed 2023 Distribution Rates**

**A Data Inputs (from Sheet 10. Load Forecast)**

| Test Year Billing Determinants for Residential Class | |
|---|---|
| Customers | 543,965 |
| kWh | 5,083,445,346 |

| | |
|---|---|
| Proposed Residential Class Specific Revenue Requirement[1] | $ 407,081,613.65 |

| Residential Base Rates on Current Tariff | |
|---|---|
| Monthly Fixed Charge ($) | $ 56.340 |
| Distribution Volumetric Rate ($/kWh) | $ 0.0111 |

**B Current Fixed/Variable Split**

| | Base Rates | Billing Determinants | Revenue | % of Total Revenue |
|---|---|---|---|---|
| Fixed | $ 56.34 | 543,965 | $ 367,763,767.35 | 86.70% |
| Variable | $ 0.0111 | 5,083,445,346 | $ 56,426,243.34 | 13.30% |
| **TOTAL** | - | - | $ 424,190,010.69 | - |

**C Calculating Test Year Base Rates**

| | |
|---|---|
| Number of Remaining Rate Design Policy Transition Years[2] | 2 |

| | Test Year Revenue @ Current F/V Split | Test Year Base Rates @ Current F/V Split | Reconciliation - Test Year Base Rates @ Current F/V Split |
|---|---|---|---|
| Fixed | $ 352,931,148.97 | $ 54.07 | $ 352,946,164.37 |
| Variable | $ 54,150,464.67 | $ 0.0107 | $ 54,392,865.20 |
| TOTAL | $ 407,081,613.65 | - | $ 407,339,029.57 |

| | New F/V Split | Revenue @ new F/V Split | Final Adjusted Base Rates | Revenue Reconciliation @ Adjusted Rates |
|---|---|---|---|---|
| Fixed | 93.35% | $ 380,006,381.31 | $ 58.22 | $ 380,035,614.76 |
| Variable | 6.65% | $ 27,075,232.34 | $ 0.0053 | $ 26,942,260.33 |
| TOTAL | - | $ 407,081,613.65 | - | $ 406,977,875.09 |

| Checks[3] | |
|---|---|
| Change in Fixed Rate | $ 4.15 |
| Difference Between Revenues @ Proposed Rates and Class Specific Revenue Requirement | ($103,738.56) |
| | -0.03% |

Ontario Energy Board

# Revenue Requirement Workform (RRWF) for 2023 Filers

New Rate Design Policy For Residential Customers
Please complete the following tables.

**Year-Round Medium Density Residential (R1) - Proposed 2024 Distribution Rates**

**A Data Inputs (from Sheet 10. Load Forecast)**

| Test Year Billing Determinants for Residential Class | |
|---|---|
| Customers | 548,767 |
| kWh | 5,119,903,869 |

| | |
|---|---|
| Proposed Residential Class Specific Revenue Requirement[1] | $ 427,100,055.46 |

| Residential Base Rates on Current Tariff | |
|---|---|
| Monthly Fixed Charge ($) | $ 58.22 |
| Distribution Volumetric Rate ($/kWh) | $ 0.0053 |

**B Current Fixed/Variable Split**

| | Base Rates | Billing Determinants | Revenue | % of Total Revenue |
|---|---|---|---|---|
| Fixed | $ 58.22 | 548,767 | $ 383,390,548.56 | 93.39% |
| Variable | $ 0.0053 | 5,119,903,869 | $ 27,135,490.51 | 6.61% |
| **TOTAL** | - | - | $ 410,526,039.07 | - |

**C Calculating Test Year Base Rates**

| | |
|---|---|
| Number of Remaining Rate Design Policy Transition Years[2] | 1 |

| | Test Year Revenue @ Current F/V Split | Test Year Base Rates @ Current F/V Split | Reconciliation - Test Year Base Rates @ Current F/V Split |
|---|---|---|---|
| Fixed | $ 398,869,033.80 | $ 60.57 | $ 398,865,776.81 |
| Variable | $ 28,231,021.66 | $ 0.0055 | $ 28,159,471.28 |
| TOTAL | $ 427,100,055.46 | - | $ 427,025,248.10 |

| | New F/V Split | Revenue @ new F/V Split | Final Adjusted Base Rates | Revenue Reconciliation @ Adjusted Rates |
|---|---|---|---|---|
| Fixed | 100.00% | $ 427,100,055.46 | $ 64.86 | $ 427,116,299.89 |
| Variable | 0.00% | $ - | $ - | $ - |
| TOTAL | - | $ 427,100,055.46 | - | $ 427,116,299.89 |

| Checks[3] | |
|---|---|
| Change in Fixed Rate | $ 4.29 |
| Difference Between Revenues @ Proposed Rates and Class Specific Revenue Requirement | $16,244.43 |
| | 0.00% |

Ontario Energy Board

# Revenue Requirement Workform (RRWF) for 2023 Filers

New Rate Design Policy For Residential Customers
Please complete the following tables.

**Year-Round Low Density Residential (R2) - Proposed 2023 Distribution Rates**

**A Data Inputs (from Sheet 10. Load Forecast)**

| Test Year Billing Determinants for Residential Class | |
|---|---|
| Customers | 415,856 |
| kWh | 4,828,339,924 |

| | |
|---|---|
| Proposed Residential Class Specific Revenue Requirement[1] | $ 631,714,604.03 |

| Residential Base Rates on Current Tariff | |
|---|---|
| Monthly Fixed Charge ($) | $ 115.27 |
| Distribution Volumetric Rate ($/kWh) | $ 0.0171 |

**B Current Fixed/Variable Split**

| | Base Rates | Billing Determinants | Revenue | % of Total Revenue |
|---|---|---|---|---|
| Fixed | $ 115.27 | 415,856 | $ 575,228,360.54 | 87.45% |
| Variable | $ 0.0171 | 4,828,339,924 | $ 82,564,612.71 | 12.55% |
| **TOTAL** | - | - | $ 657,792,973.25 | - |

**C Calculating Test Year Base Rates**

| | |
|---|---|
| Number of Remaining Rate Design Policy Transition Years[2] | 2 |

| | Test Year Revenue @ Current F/V Split | Test Year Base Rates @ Current F/V Split | Reconciliation - Test Year Base Rates @ Current F/V Split |
|---|---|---|---|
| Fixed | $ 552,423,286.33 | $ 110.70 | $ 552,422,829.11 |
| Variable | $ 79,291,317.70 | $ 0.0164 | $ 79,184,774.76 |
| TOTAL | $ 631,714,604.03 | - | $ 631,607,603.87 |

| | New F/V Split | Revenue @ new F/V Split | Final Adjusted Base Rates | Revenue Reconciliation @ Adjusted Rates |
|---|---|---|---|---|
| Fixed | 93.72% | $ 592,068,945.18 | $ 118.64 | $ 592,045,568.62 |
| Variable | 6.28% | $ 39,645,658.85 | $ 0.0082 | $ 39,592,387.38 |
| TOTAL | - | $ 631,714,604.03 | - | $ 631,637,956.00 |

| Checks[3] | |
|---|---|
| Change in Fixed Rate | $ 7.94 |
| Difference Between Revenues @ Proposed Rates and Class Specific Revenue Requirement | ($76,648.03) |
| | -0.01% |

Ontario Energy Board

# Revenue Requirement Workform (RRWF) for 2023 Filers

New Rate Design Policy For Residential Customers
Please complete the following tables.

**Year-Round Low Density Residential (R2) - Proposed 2024 Distribution Rates**

**A Data Inputs (from Sheet 10. Load Forecast)**

| Test Year Billing Determinants for Residential Class | |
|---|---|
| Customers | 417,937 |
| kWh | 4,822,322,320 |

| | |
|---|---|
| Proposed Residential Class Specific Revenue Requirement[1] | $ 660,015,482.31 |

| Residential Base Rates on Current Tariff | |
|---|---|
| Monthly Fixed Charge ($) | $ 118.64 |
| Distribution Volumetric Rate ($/kWh) | $ 0.0082 |

**B Current Fixed/Variable Split**

| | Base Rates | Billing Determinants | Revenue | % of Total Revenue |
|---|---|---|---|---|
| Fixed | $ 118.64 | 417,937 | $ 595,009,117.06 | 93.77% |
| Variable | $ 0.0082 | 4,822,322,320 | $ 39,543,043.03 | 6.23% |
| **TOTAL** | - | - | $ 634,552,160.09 | - |

**C Calculating Test Year Base Rates**

| | |
|---|---|
| Number of Remaining Rate Design Policy Transition Years[2] | 1 |

| | Test Year Revenue @ Current F/V Split | Test Year Base Rates @ Current F/V Split | Reconciliation - Test Year Base Rates @ Current F/V Split |
|---|---|---|---|
| Fixed | $ 618,885,655.23 | $ 123.40 | $ 618,881,701.32 |
| Variable | $ 41,129,827.08 | $ 0.0085 | $ 40,989,739.72 |
| TOTAL | $ 660,015,482.31 | - | $ 659,871,441.05 |

| | New F/V Split | Revenue @ new F/V Split | Final Adjusted Base Rates | Revenue Reconciliation @ Adjusted Rates |
|---|---|---|---|---|
| Fixed | 100.00% | $ 660,015,482.31 | $ 131.60 | $ 660,006,741.44 |
| Variable | 0.00% | $ - | $ - | $ - |
| TOTAL | - | $ 660,015,482.31 | - | $ 660,006,741.44 |

| Checks[3] | |
|---|---|
| Change in Fixed Rate | $ 8.20 |
| Difference Between Revenues @ Proposed Rates and Class Specific Revenue Requirement | ($8,740.86) |
| | 0.00% |

| 2023 CSTA Rate Adder* | | | |
|---|---|---|---|
| **Class** | **Credit Amount to be Recovered** | **Forecast Demand (kW)** | **CSTA Rate Adder ($/kW)** |
| **DGen** | $103,062 | 210,462 | $0.4897 |
| **GSd** | $680,339 | 6,995,713 | $0.0973 |
| **UGd** | $302,515 | 2,304,119 | $0.1313 |
| **AUGd** | $105,445 | 334,039 | $0.3157 |
| **AGSd** | $164,242 | 646,691 | $0.2540 |
| **TOTAL** | **$1,355,604** | **10,491,024** | |

* CSTA rate adder will remain unchanged for 2023-2027.

| 2023-2027 Hopper Foundry Rate Adder | | |
|---|---|---|
| **Year** | **Lost Revenue Amount ($)** | **Hopper Foundry Rate Adder ($/kW)** |
| **2023** | 87,938 | 0.0126 |
| **2024** | 91,635 | 0.0131 |
| **2025** | 94,933 | 0.0138 |
| **2026** | 99,422 | 0.0145 |
| **2027** | 103,012 | 0.0150 |

## 2023 Revenue Reconciliation

| Rate Class | Customers/ Connections | Number of Customers/ Connections (Average) | Test Year Consumption kWh* | Test Year Consumption kW | Draft Rates Monthly Service Charge | Draft Rates Volumetric** kWh | Draft Rates Volumetric** kW | Revenues at Draft Rates | Class Specific Revenue Requirement | Transformer Allowance Credit*** | Total | Difference |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Residential – Urban [UR] | Customers | 246,136 | 2,024,934,137 | - | $ 36.54 | $ - | $ - | $ 107,925,907 | $ 107,930,332 | | $ 107,930,332 | $ 4,425 |
| Residential – Medium Density [R1] | Customers | 543,965 | 5,083,445,346 | - | $ 58.22 | $ 0.0053 | $ - | $ 406,977,875 | $ 407,081,614 | | $ 407,081,614 | $ 103,739 |
| Residential – Low Density [R2] | Customers | 337,179 | 4,828,339,924 | - | $ 118.64 | $ 0.0187 | $ - | $ 570,324,442 | $ 570,113,427 | | $ 570,113,427 | -$ 211,015 |
| Seasonal Residential - Low Density [Seas-R2] | Customers | 78,677 | - | - | $ 65.25 | $ - | $ - | $ 61,604,208 | $ 61,601,178 | | $ 61,601,178 | -$ 3,030 |
| General Service Energy Billed (less than 50 kW) [GSe] | Customers | 88,795 | 1,994,844,246 | - | $ 31.33 | $ 0.0661 | $ - | $ 165,242,542 | $ 165,196,627 | | $ 165,196,627 | -$ 45,915 |
| General Service Demand Billed (50 kW and above) [GSd] | Customers | 5,343 | 2,182,644,295 | 6,995,713 | $ 100.82 | $ - | $ 18.7295 | $ 137,489,898 | $ 136,720,849 | $ 768,277 | $ 137,489,126 | -$ 771 |
| Urban General Service Energy Billed (less than 50 kW) [UGe] | Customers | 18,432 | 547,270,602 | - | $ 24.39 | $ 0.0317 | $ - | $ 22,743,161 | $ 22,753,188 | | $ 22,753,188 | $ 10,027 |
| Urban General Service Demand Billed (50 kW and above) [UGd] | Customers | 1,743 | 883,486,610 | 2,304,119 | $ 92.16 | $ - | $ 10.8745 | $ 26,983,727 | $ 26,681,246 | $ 302,515 | $ 26,983,761 | $ 35 |
| Street Lighting | Customers | 5,494 | 83,384,291 | - | $ 3.01 | $ 0.1083 | $ - | $ 9,228,959 | $ 9,226,928 | | $ 9,226,928 | -$ 2,031 |
| Sentinel Lighting | Customers | 19,409 | 11,385,518 | - | $ 3.01 | $ 0.1658 | $ - | $ 2,588,788 | $ 2,589,041 | | $ 2,589,041 | $ 254 |
| Unmetered Scattered Load [USL] | Customers | 5,752 | 32,640,414 | - | $ 36.72 | $ 0.0231 | $ - | $ 3,288,739 | $ 3,288,867 | | $ 3,288,867 | $ 128 |
| Distributed Generation [DGen] | Customers | 1,489 | 30,291,879 | 210,462 | $ 190.79 | $ - | $ 11.0564 | $ 5,736,730 | $ 5,633,628 | $ 103,062 | $ 5,736,690 | -$ 40 |
| Residential – Acquired Urban [AUR] | Customers | 15,476 | 118,127,033 | - | $ 30.17 | $ - | $ - | $ 5,603,002 | $ 5,603,809 | | $ 5,603,809 | $ 807 |
| Urban Acquired General Service Energy Billed (less than 50 kW) [AUGe] | Customers | 1,380 | 40,925,460 | - | $ 25.59 | $ 0.0148 | $ - | $ 1,029,498 | $ 1,027,533 | | $ 1,027,533 | -$ 1,965 |
| Urban Acquired General Service Demand Billed (50 kW and above) [AUGd] | Customers | 207 | 118,498,175 | 334,039 | $ 146.47 | $ - | $ 2.7207 | $ 1,273,178 | $ 1,167,719 | $ 105,445 | $ 1,273,165 | -$ 13 |
| Residential – Acquired Mixed Density [AR] | Customers | 38,991 | 336,111,907 | - | $ 36.64 | $ - | $ - | $ 17,143,532 | $ 17,142,378 | | $ 17,142,378 | -$ 1,154 |
| Acquired General Service Energy Billed (less than 50 kW) [AGSe] | Customers | 4,223 | 117,355,731 | - | $ 38.38 | $ 0.0176 | $ - | $ 4,010,339 | $ 4,007,132 | | $ 4,007,132 | -$ 3,208 |
| Acquired General Service Demand Billed (50 kW and above) [AGSd] | Customers | 303 | 231,447,531 | 646,691 | $ 170.26 | $ - | $ 4.4259 | $ 3,481,589 | $ 3,317,347 | $ 164,242 | $ 3,481,589 | $ 1 |
| Sub-Transmission [ST] | | 910 | 15,070,145,145 | 30,805,724 | | | | $ 61,611,349 | $ 61,611,805 | | $ 61,611,805 | $ 456 |
| *Service Charge* | Customers | 910 | | | $ 790.43 | | | $ 8,631,496 | | | | |
| *Meter Charge* | | 608 | | | $ 396.96 | | | $ 2,896,220 | | | | |
| *Common Line* | | | | 30,260,193 | | | $ 1.4769 | $ 44,691,279 | | | | |
| *Specific ST Line** | Kilometers | | | 723 | | | $ 595.4935 | $ 430,692 | | | | |
| *HVDS-high* | | | | 1,128,331 | | | $ 2.9907 | $ 3,374,499 | | | | |
| *HVDS-low* | | | | 65,965 | | | $ 4.8501 | $ 319,935 | | | | |
| *LVDS-low* | | | | 681,526 | | | $ 1.8594 | $ 1,267,229 | | | | |
| **Total** | | | | | | | | $ 1,614,287,462 | $ 1,612,694,647 | $ 1,443,542 | $ 1,614,138,190 | -$ 149,272 |

* kWh for Residential-Low Density [R2] class includes the consumption associated with seasonal customers moving to R2 class
** Volumetric rate for GSd class includes Hopper Foundry Rate Adder, along with CSTA Rate Adder
*** Tranformer Allowance for GSd class includes $680,339 for CSTA credit and $87,938 for Hopper Foundry credit

**Note**

1 The class specific revenue requirements in column K must be the amounts used in the final rate design process. The total of column K should equate to the rates revenue requirement.

2 Rates should be entered with the number of decimal places that will show on the Tariff of Rates and Charges.

| UTR | Proceeding | Network $/kW | Line Connection $/kW | Transformation Connection $/kW |
|---|---|---|---|---|
| **2022 UTR** | **EB-2022-0084** | **$ 5.46** | **$ 0.88** | **$ 2.81** |

| | **2023 Forecast Charge Determinants** | | | **Allocators: Sum of 2023 Individual Peaks, coincident with Tx DP Peak** | | | **2023 Proposed Tx Charges** | | | | **2023 Proposed RTSR** | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | | | **Energy Billed Classes** | | **Demand Billed Classes** | | |
| | **Network** | **Line Connection** | **Transformation Connection** | **Network** | **Line Connection** | **Transformation Connection** | **Network** | **Line Connection** | **Transformation Connection** | **Total** | | | | | |
| IESO Bill | | | | 63,562,090 | 57,994,416 | 65,129,506 | $ 347,049,010 | $ 51,035,086 | $ 183,013,912 | $581,098,008 | | | Network $/kW | Line Connection $/kW | Transformation Connection $/kW |
| ST | 30,688,263 | 30,291,296 | 24,553,112 | 26,161,166 | 20,845,117 | 25,272,700 | $ 142,839,966 | $ 18,343,703 | $ 71,016,288 | $232,199,957 | | | $ 4.6545 | $ 0.6056 | $ 2.8924 |
| Non-ST Rate Classes | | | | | | | $ 204,209,043 | $ 32,691,383 | $ 111,997,624 | $348,898,050 | | | | | |
| | kWh w loss | kW w loss | | CP Tx % | CP Dx % | | Network | Connection | | | Network $/kWh | Connection $/kWh | Network $/kW | Connection $/kW | |
| UR | 2,140,355,383 | | | 12.44% | 12.11% | | $ 25,413,138 | $ 17,518,796 | | | $ 0.0119 | $ 0.0082 | | | |
| R1 | 5,469,787,192 | | | 29.56% | 29.03% | | $ 60,357,867 | $ 42,007,090 | | | $ 0.0110 | $ 0.0077 | | | |
| R2 | 5,335,315,616 | | | 26.62% | 26.53% | | $ 54,366,320 | $ 38,379,702 | | | $ 0.0102 | $ 0.0072 | | | |
| GSe | 2,186,349,294 | | | 9.34% | 9.81% | | $ 19,076,693 | $ 14,188,179 | | | $ 0.0087 | $ 0.0065 | | | |
| GSd | 2,315,785,597 | 7,422,452 | | 9.70% | 10.03% | | $ 19,807,858 | $ 14,513,080 | | | | | $ 2.6686 | $ 1.9553 | |
| UGe | 583,937,732 | | | 2.67% | 2.77% | | $ 5,447,485 | $ 4,012,204 | | | $ 0.0093 | $ 0.0069 | | | |
| UGd | 927,660,940 | 2,419,325 | | 4.08% | 4.15% | | $ 8,338,991 | $ 6,005,091 | | | | | $ 3.4468 | $ 2.4821 | |
| USL | 35,643,332 | | | 0.13% | 0.13% | | $ 263,080 | $ 184,244 | | | $ 0.0074 | $ 0.0052 | | | |
| Dgen | 32,139,684 | 223,300 | | 0.16% | 0.13% | | $ 327,035 | $ 187,344 | | | | | $ 1.4646 | $ 0.8390 | |
| STL | 91,055,646 | | | 0.28% | 0.30% | | $ 581,575 | $ 433,770 | | | $ 0.0064 | $ 0.0048 | | | |
| Sen Lgt | 12,432,986 | | | 0.04% | 0.04% | | $ 79,814 | $ 59,272 | | | $ 0.0064 | $ 0.0048 | | | |
| AUR | 123,206,496 | | | 0.73% | 0.71% | | $ 1,500,825 | $ 1,032,097 | | | $ 0.0122 | $ 0.0084 | | | |
| AUGe | 42,685,255 | | | 0.20% | 0.20% | | $ 399,750 | $ 291,596 | | | $ 0.0094 | $ 0.0068 | | | |
| AUGd | 122,408,614 | 345,062 | | 0.53% | 0.54% | | $ 1,091,080 | $ 783,233 | | | | | $ 3.1620 | $ 2.2698 | |
| AR | 357,623,069 | | | 2.03% | 2.00% | | $ 4,154,634 | $ 2,893,737 | | | $ 0.0116 | $ 0.0081 | | | |
| AGSe | 124,866,497 | | | 0.56% | 0.58% | | $ 1,148,516 | $ 834,929 | | | $ 0.0092 | $ 0.0067 | | | |
| AGSd | 243,714,250 | 680,966 | | 0.91% | 0.94% | | $ 1,854,384 | $ 1,364,644 | | | | | $ 2.7232 | $ 2.0040 | |

# DVA GROUP 1 WORKFORM

This schedule has been filed separately in MS Excel format.

# DVA GROUP 2 WORKFORM

This schedule has been filed separately in MS Excel format.

# RATE RIDER - NORFOLK & WOODSTOCK'S 1595 ACCOUNTS

This schedule has been filed separately in MS Excel format.

# RATE RIDER - NORFOLK, HALDIMAND & WOODSTOCK'S 1592 ACCOUNTS

This schedule has been filed separately in MS Excel format.

| Rate Class | Consumption Level | Monthly Consumption (kWh) | Monthly Peak (kW) | Current Total Bill | Change in DX Bill ($) | Change in DX Bill (%) | Change in Total Bill ($) | Change in Total Bill (%) |
|---|---|---|---|---|---|---|---|---|
| UR | Low | 340 | | $80.16 | ($1.84) | -4.73% | ($1.46) | -1.82% |
| | Typical | 750 | | $131.79 | ($2.13) | -5.47% | ($1.40) | -1.06% |
| | Average | 690 | | $124.24 | ($2.08) | -5.36% | ($1.41) | -1.14% |
| | High | 1,260 | | $196.02 | ($2.48) | -6.39% | ($1.33) | -0.68% |
| R1 (with DRP) | Low | 370 | | $82.37 | ($0.47) | -1.27% | ($0.14) | -0.17% |
| | Typical | 750 | | $130.55 | ($0.73) | -1.99% | ($0.08) | -0.06% |
| | Average | 784 | | $134.86 | ($0.76) | -2.06% | ($0.08) | -0.06% |
| | High | 1,650 | | $244.66 | ($1.37) | -3.70% | $0.05 | 0.02% |
| R1 (without DRP) | Low | 370 | | $105.39 | ($0.05) | -0.08% | $0.25 | 0.24% |
| | Typical | 750 | | $157.14 | ($2.10) | -3.22% | ($1.37) | -0.87% |
| | Average | 784 | | $161.77 | ($2.28) | -3.49% | ($1.51) | -0.94% |
| | High | 1,650 | | $279.72 | ($6.96) | -9.39% | ($5.21) | -1.86% |
| R2 (with DRP) | Low | 440 | | $92.24 | ($0.75) | -2.03% | ($0.43) | -0.47% |
| | Typical | 750 | | $132.25 | ($0.97) | -2.62% | ($0.44) | -0.33% |
| | Average | 978 | | $161.68 | ($1.12) | -3.05% | ($0.45) | -0.28% |
| | High | 2,110 | | $307.77 | ($1.92) | -5.20% | ($0.49) | -0.16% |
| R2 (without DRP) | Low | 440 | | $132.36 | ($9.45) | -11.89% | ($8.62) | -6.51% |
| | Typical | 750 | | $177.03 | ($8.83) | -10.46% | ($7.84) | -4.43% |
| | Average | 978 | | $209.89 | ($8.37) | -9.51% | ($7.27) | -3.46% |
| | High | 2,110 | | $373.03 | ($6.11) | -5.75% | ($4.43) | -1.19% |
| Seasonal-UR | Low | 40 | | $63.67 | ($23.27) | -37.86% | ($21.89) | -34.38% |
| | Average | 369 | | $114.94 | ($33.73) | -47.05% | ($31.68) | -27.56% |
| | High | 1,040 | | $219.49 | ($55.07) | -59.50% | ($51.63) | -23.52% |
| Seasonal-R1 | Low | 40 | | $63.67 | ($1.48) | -2.41% | ($1.35) | -2.12% |
| | Average | 369 | | $114.94 | ($10.20) | -14.22% | ($9.21) | -8.01% |
| | High | 1,040 | | $219.49 | ($27.98) | -30.23% | ($25.24) | -11.50% |
| Seasonal-R2 | Low | 40 | | $63.67 | $5.86 | 9.53% | $5.64 | 8.85% |
| | Average | 369 | | $114.94 | $1.55 | 2.16% | $2.61 | 2.27% |
| | High | 1,040 | | $219.49 | ($7.24) | -7.83% | ($3.56) | -1.62% |
| GSe | Low | 60 | | $45.40 | ($2.97) | -7.54% | ($2.72) | -6.00% |
| | Typical | 2,000 | | $416.29 | ($8.60) | -4.90% | ($5.62) | -1.35% |
| | Average | 1,887 | | $394.69 | ($8.27) | -4.93% | ($5.45) | -1.38% |
| | High | 5,570 | | $1,098.80 | ($18.95) | -4.45% | ($10.94) | -1.00% |
| UGe | Low | 180 | | $54.60 | ($2.83) | -8.38% | ($2.39) | -4.38% |
| | Typical | 2,000 | | $334.78 | ($5.56) | -5.88% | ($2.22) | -0.66% |
| | Average | 2,494 | | $410.83 | ($6.30) | -5.67% | ($2.17) | -0.53% |
| | High | 6,930 | | $1,093.72 | ($12.96) | -5.00% | ($1.75) | -0.16% |
| GSd | Low | 9,310 | 55 | $3,025.72 | ($72.93) | -5.96% | ($47.50) | -1.57% |
| | Average | 34,334 | 110 | $8,233.25 | ($148.02) | -6.35% | ($97.43) | -1.18% |
| | High | 75,790 | 250 | $18,211.52 | ($317.92) | -6.18% | ($200.54) | -1.10% |
| UGd | Low | 13,900 | 55 | $3,214.88 | ($58.39) | -7.83% | ($23.90) | -0.74% |
| | Average | 42,592 | 111 | $8,483.00 | ($118.74) | -8.51% | ($49.23) | -0.58% |
| | High | 97,610 | 280 | $19,777.79 | ($271.01) | -8.08% | ($91.98) | -0.47% |
| St Lgt | Low | 30 | | $10.59 | ($0.89) | -12.10% | ($0.81) | -7.67% |
| | Average | 1,274 | | $301.26 | ($8.60) | -5.63% | ($7.18) | -2.38% |
| | High | 2,310 | | $552.88 | ($15.02) | -5.49% | ($12.47) | -2.26% |
| Sen Lgt | Low | 20 | | $9.11 | ($0.37) | -5.34% | ($0.34) | -3.73% |
| | Average | 49 | | $17.42 | ($0.64) | -5.20% | ($0.57) | -3.29% |
| | High | 80 | | $26.30 | ($0.92) | -5.14% | ($0.82) | -3.13% |
| USL | Low | 100 | | $52.75 | ($3.52) | -8.11% | ($3.22) | -6.10% |
| | Average | 477 | | $106.37 | ($5.18) | -9.66% | ($4.43) | -4.17% |
| | High | 550 | | $116.75 | ($5.50) | -9.89% | ($4.67) | -4.00% |
| DGen | Low | 10 | 0.03 | $229.44 | ($8.58) | -4.26% | ($9.69) | -4.22% |
| | Average | 1,709 | 12 | $658.49 | ($11.91) | -3.56% | ($8.98) | -1.36% |
| | High | 8,490 | 45 | $2,150.30 | ($23.09) | -3.30% | ($9.29) | -0.43% |
| ST | Low | 88,780 | 500 | $19,594.54 | ($515.61) | -22.85% | ($115.44) | -0.59% |
| | Average | 1,373,443 | 2,808 | $228,266.98 | ($2,806.72) | -45.85% | ($547.81) | -0.24% |
| | High | 2,641,420 | 13,730 | $524,849.82 | ($9,171.38) | -37.57% | $2,465.62 | 0.47% |

| Rate Class | Consumption Level | Monthly Consumption (kWh) | Monthly Peak (kW) | Current Total Bill | Change in DX Bill ($) | Change in DX Bill (%) | Change in Total Bill ($) | Change in Total Bill (%) |
|---|---|---|---|---|---|---|---|---|
| **WHSI to HONI** | | | | | | | | |
| AUR-WHSI | Low | 310 | | $60.43 | $5.45 | 22.59% | $7.10 | 11.76% |
| | Typical | 750 | | $112.99 | $5.06 | 20.83% | $9.53 | 8.44% |
| | Average | 636 | | $99.37 | $5.16 | 21.29% | $8.90 | 8.96% |
| | High | 1,160 | | $161.97 | $4.69 | 19.21% | $11.80 | 7.28% |
| AUGe-WHSI | Low | 190 | | $54.26 | ($4.12) | -12.48% | ($3.28) | -6.04% |
| | Typical | 2,000 | | $289.48 | $4.39 | 7.87% | $10.39 | 3.59% |
| | Average | 2,471 | | $350.69 | $6.60 | 10.70% | $13.95 | 3.98% |
| | High | 7,240 | | $970.46 | $29.02 | 23.82% | $49.96 | 5.15% |
| AUGd-WHSI | Low | 9,370 | 50 | $1,974.60 | $27.62 | 10.29% | $21.41 | 1.08% |
| | Average | 47,636 | 134 | $8,276.34 | $53.09 | 11.22% | $2.11 | 0.03% |
| | High | 137,890 | 340 | $23,210.73 | $118.88 | 12.19% | ($36.41) | -0.16% |
| St Lgt-WHSI | Average | 37,079 | 104 | $8,934.52 | $1,053.93 | 36.41% | $1,465.44 | 16.40% |
| USL-WHSI | Average | 1,349 | | $182.65 | $45.26 | 215.50% | $50.22 | 27.50% |
| ST-WHSI | Average | 895,853 | 3,301 | $159,529.92 | ($3,229.49) | -35.26% | $7,259.05 | 4.55% |
| **NPDI to HONI** | | | | | | | | |
| AR-NPDI | Low | 290 | | $72.04 | ($3.30) | -8.38% | ($0.42) | -0.58% |
| | Typical | 750 | | $126.93 | ($4.18) | -10.42% | $3.02 | 2.38% |
| | Average | 692 | | $120.01 | ($4.06) | -10.16% | $2.58 | 2.15% |
| | High | 1,230 | | $184.21 | ($5.09) | -12.47% | $6.60 | 3.58% |
| AGSe-NPDI | Low | 110 | | $66.23 | ($14.84) | -26.54% | ($13.23) | -19.98% |
| | Typical | 2,000 | | $332.19 | ($16.73) | -16.07% | ($2.45) | -0.74% |
| | Average | 2,377 | | $385.24 | ($17.11) | -15.04% | ($0.30) | -0.08% |
| | High | 6,410 | | $952.76 | ($21.14) | -9.76% | $22.71 | 2.38% |
| AGSd-NPDI | Low | 13,020 | 55 | $2,739.22 | ($122.44) | -23.32% | ($70.74) | -2.58% |
| | Average | 70,294 | 181 | $12,326.88 | ($221.18) | -19.58% | ($2.27) | -0.02% |
| | High | 129,420 | 300 | $22,113.41 | ($319.21) | -18.77% | $61.63 | 0.28% |
| St Lgt-NPDI | Average | 11,389 | 39 | $2,393.70 | $206.71 | 20.57% | $257.02 | 10.74% |
| Sen Lgt-NPDI | Average | 108 | 0.3 | $25.33 | $6.61 | 47.28% | $6.84 | 27.00% |
| USL-NPDI | Average | 904 | | $128.34 | $29.92 | 116.47% | $34.39 | 26.79% |
| **HCHI to HONI** | | | | | | | | |
| AR-HCHI | Low | 250 | | $65.47 | ($0.63) | -1.70% | $1.05 | 1.60% |
| | Typical | 750 | | $126.21 | ($1.28) | -3.43% | $3.70 | 2.93% |
| | Average | 742 | | $125.24 | ($1.26) | -3.40% | $3.66 | 2.92% |
| | High | 1,410 | | $206.39 | ($2.13) | -5.65% | $7.21 | 3.49% |
| AGSe-HCHI | Low | 90 | | $39.73 | $9.89 | 33.03% | $9.65 | 24.28% |
| | Typical | 2,000 | | $303.45 | $3.59 | 5.33% | $10.85 | 3.58% |
| | Average | 2,261 | | $339.49 | $2.73 | 3.76% | $11.02 | 3.24% |
| | High | 5,430 | | $777.06 | ($7.73) | -5.74% | $13.02 | 1.67% |
| AGSd-HCHI | Low | 10,880 | 55 | $2,264.04 | $69.27 | 22.01% | $70.54 | 3.12% |
| | Average | 57,529 | 175 | $10,343.59 | $18.12 | 2.24% | ($9.89) | -0.10% |
| | High | 135,160 | 375 | $23,792.31 | ($67.03) | -4.10% | ($143.77) | -0.60% |
| St Lgt-HCHI | Average | 31,001 | 85 | $10,861.18 | ($2,135.02) | -39.63% | ($2,223.80) | -20.47% |
| Sen Lgt-HCHI | Average | 61 | 0.2 | $28.18 | ($9.61) | -42.98% | ($8.86) | -31.45% |
| USL-HCHI | Average | 471 | | $74.21 | $25.48 | 118.77% | $25.61 | 34.51% |

# 2023 BILL IMPACTS

This schedule has been filed separately in MS Excel format.

# 2023-2027 COMBINED BILL IMPACTS

This schedule has been filed separately in MS Excel format.

**Combined Bill Impacts of Changes in Transmission and Distribution Revenue Requirements ($)**

| Rate Class | Monthly Consumption (kWh) | | 2023 | | | 2024 | | | 2025 | | | 2026 | | | 2027 | | | 5-year average | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | Change in Total Bill ($) - Prefiled | Change in Total Bill ($) - March 2022 | Change in Total Bill ($) - As settled | Change in Total Bill ($) - Prefiled | Change in Total Bill ($) - March 2022 | Change in Total Bill ($) - As settled | Change in Total Bill ($) - Prefiled | Change in Total Bill ($) - March 2022 | Change in Total Bill ($) - As settled | Change in Total Bill ($) - Prefiled | Change in Total Bill ($) - March 2022 | Change in Total Bill ($) - As settled | Change in Total Bill ($) - Prefiled | Change in Total Bill ($) - March 2022 | Change in Total Bill ($) - As settled | Change in Total Bill ($) - Prefiled | Change in Total Bill ($) - March 2022 | Change in Total Bill ($) - As settled |
| R1 (without DRP) | 750 | DX Impact | ($2.78) | ($1.46) | ($1.37) | $1.40 | $1.56 | $1.04 | $2.36 | $2.64 | $2.09 | $3.18 | $2.95 | $3.54 | $2.26 | $2.91 | $2.28 | $1.29 | $1.72 | $1.52 |
| | | TX Impact | ($0.43) | ($0.30) | ($0.49) | $0.49 | $0.82 | $0.65 | $0.61 | $0.80 | $0.78 | $0.77 | $1.00 | $0.78 | $0.52 | $0.59 | $0.47 | $0.39 | $0.58 | $0.44 |
| | | Combined Impact | ($3.20) | ($1.76) | ($1.86) | $1.89 | $2.38 | $1.69 | $2.97 | $3.44 | $2.87 | $3.95 | $3.95 | $4.32 | $2.78 | $3.50 | $2.74 | $1.68 | $2.30 | $1.95 |
| GSe | 2,000 | DX Impact | ($8.32) | ($5.76) | ($5.62) | $1.43 | $2.18 | $1.03 | $6.12 | $6.98 | $5.65 | $8.38 | $9.25 | $9.41 | $6.99 | $7.79 | $6.21 | $2.92 | $4.09 | $3.33 |
| | | TX Impact | ($0.90) | ($0.64) | ($1.04) | $1.03 | $1.74 | $1.38 | $1.30 | $1.70 | $1.65 | $1.62 | $2.12 | $1.65 | $1.11 | $1.26 | $0.99 | $0.83 | $1.24 | $0.93 |
| | | Combined Impact | ($9.22) | ($6.40) | ($6.66) | $2.46 | $3.92 | $2.40 | $7.42 | $8.68 | $7.30 | $10.00 | $11.37 | $11.06 | $8.10 | $9.05 | $7.20 | $3.75 | $5.33 | $4.26 |

**Combined Bill Impacts of Changes in Transmission and Distribution Revenue Requirements (%)**

| Rate Class | Monthly Consumption (kWh) | | 2023 | | | 2024 | | | 2025 | | | 2026 | | | 2027 | | | 5-year average | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | Change in Total Bill (%) - Prefiled | Change in Total Bill (%) - March 2022 | Change in Total Bill (%) - As settled | Change in Total Bill (%) - Prefiled | Change in Total Bill (%) - March | Change in Total Bill (%) - As settled | Change in Total Bill (%) - Prefiled | Change in Total Bill (%) - March | Change in Total Bill (%) - As settled | Change in Total Bill (%) - Prefiled | Change in Total Bill (%) - March | Change in Total Bill (%) - As settled | Change in Total Bill (%) - Prefiled | Change in Total Bill (%) - March | Change in Total Bill (%) - As settled | Change in Total Bill (%) - Prefiled | Change in Total Bill (%) - March | Change in Total Bill (%) - As settled |
| R1 (without DRP) | 750 | DX Impact | -1.8% | -0.9% | -0.9% | 0.9% | 1.0% | 0.7% | 1.5% | 1.7% | 1.3% | 2.0% | 1.8% | 2.2% | 1.4% | 1.8% | 1.4% | 0.8% | 1.1% | 1.0% |
| | | TX Impact | -0.3% | -0.2% | -0.4% | 0.4% | 0.6% | 0.5% | 0.5% | 0.6% | 0.6% | 0.6% | 0.8% | 0.6% | 0.4% | 0.4% | 0.3% | 0.3% | 0.4% | 0.3% |
| | | Combined Impact | -2.1% | -1.2% | -1.2% | 1.3% | 1.6% | 1.2% | 2.0% | 2.3% | 1.9% | 2.6% | 2.6% | 2.8% | 1.8% | 2.2% | 1.8% | 1.1% | 1.5% | 1.3% |
| GSe | 2,000 | DX Impact | -2.0% | -1.4% | -1.3% | 0.4% | 0.5% | 0.2% | 1.5% | 1.7% | 1.4% | 2.0% | 2.2% | 2.3% | 1.7% | 1.8% | 1.5% | 0.7% | 1.0% | 0.8% |
| | | TX Impact | -0.2% | -0.2% | -0.2% | 0.3% | 0.4% | 0.3% | 0.3% | 0.4% | 0.4% | 0.4% | 0.5% | 0.4% | 0.3% | 0.3% | 0.2% | 0.2% | 0.3% | 0.2% |
| | | Combined Impact | -2.2% | -1.5% | -1.6% | 0.7% | 0.9% | 0.6% | 1.8% | 2.1% | 1.8% | 2.4% | 2.7% | 2.6% | 2.0% | 2.1% | 1.7% | 0.9% | 1.3% | 1.0% |

| Rate Class | Monthly Consumption (kWh) | | 2023 | | | 2024 | | | 2025 | | | 2026 | | | 2027 | | | 5-year average | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | Prefiled | March 2022 | As settled | Prefiled | March 2022 | As settled | Prefiled | March 2022 | As settled | Prefiled | March 2022 | As settled | Prefiled | March 2022 | As settled | Prefiled | March 2022 | As settled |
| R1 (without DRP) | 750 | $ Impact of Base Distribution Rate Change | ($1.83) | ($0.75) | ($1.37) | $2.93 | $3.10 | $2.67 | $2.51 | $2.81 | $2.22 | $3.38 | $3.14 | $3.03 | $2.40 | $3.09 | $2.42 | $1.88 | $2.28 | $1.79 |
| | | % Impact of Base Distribution Rate Change | -2.9% | -1.2% | -2.1% | 4.8% | 4.9% | 4.3% | 3.9% | 4.3% | 3.4% | 5.1% | 4.6% | 4.5% | 3.4% | 4.3% | 3.5% | 2.9% | 3.4% | 2.7% |
| GSe | 2,000 | $ Impact of Base Distribution Rate Change | ($8.05) | ($5.11) | ($6.60) | $7.22 | $8.02 | $6.60 | $6.50 | $7.42 | $6.00 | $8.91 | $9.83 | $8.00 | $7.43 | $8.28 | $6.60 | $4.40 | $5.69 | $4.12 |
| | | % Impact of Base Distribution Rate Change | -4.8% | -3.0% | -3.9% | 4.5% | 4.9% | 4.0% | 3.9% | 4.3% | 3.5% | 5.1% | 5.4% | 4.5% | 4.1% | 4.4% | 3.6% | 2.6% | 3.2% | 2.4% |

**Base distribution charges do not include DVA dispositions, Ontario Electricity Rebate and Taxes*

**Schedule A**

**To Decision and Rate Order**

**Tariff of Rates and Charges**

**OEB File No: EB-2021-0032**

**DATED: December 14, 2021**

# Hydro One Networks Inc.
## TARIFF OF RATES AND CHARGES
### Effective and Implementation Date January 1, 2022
**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2021-0032**

## RESIDENTIAL SERVICE CLASSIFICATIONS

A year-round residential customer classification applies to a customer's main place of abode and may include additional buildings served through the same meter, provided they are not rental income units. All of the following criteria must be met:

1. Occupant represents and warrants to Hydro One Networks Inc. that for so long as he/she has year-round residential rate status for the identified dwelling, he/she will not designate another property that he/she owns as a year-round residence for purposes of Hydro One rate classification.
2. Occupier must live in this residence for at least four (4) days of the week for eight (8) months of the year and the Occupier must not reside anywhere else for more than three (3) days a week during eight (8) months of the year.
3. The address of this residence must appear on documents such as the occupant's electric bill, driver's licence, credit card invoice, property tax bill, etc.
4. Occupants who are eligible to vote in Provincial of Federal elections must be enumerated for this purpose at the address of this residence.

Seasonal Residential customer classification is defined as any residential service that does not meet residential year-round criteria. It includes dwellings such as cottages, chalets and camps.

Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's conditions of Service.

### APPLICATION

Hydro One Networks' residential service area is sub-divided into three density zones according to the following:

- Urban Density Zone is defined as areas containing 3,000 or more customers with a line density of at least 60 customers per circuit kilometer.
- Medium Density Zone is defined as areas containing 100 or more customers with a line density of at least 15 customers per circuit kilometer.
- Low Density Zone is defined as areas other than Urban or Medium Density Zone.

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor’s Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

# Hydro One Networks Inc.
## TARIFF OF RATES AND CHARGES
### Effective and Implementation Date January 1, 2022
**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2021-0032**

## YEAR-ROUND URBAN DENSITY - UR
### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 38.03 |
| Base Rate Adjustment to Recover Past Tax Amounts - effective until June 30, 2023 | $ | 0.83 |
| Smart Metering Entity Charge - effective until December 31, 2022 | $ | 0.57 |
| Retail Transmission Rate - Network Service Rate (see Note 4) | $/kWh | 0.0112 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate (see Note 5) | $/kWh | 0.0081 |

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR (see Note 10) | $/kWh | 0.0030 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers (see Note 10) | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) (see Note 10) | $/kWh | 0.0005 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

## YEAR-ROUND MEDIUM DENSITY - R1**
### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 56.06 |
| Base Rate Adjustment to Recover Past Tax Amounts - effective until June 30, 2023 | $ | 1.56 |
| Smart Metering Entity Charge - effective until December 31, 2022 | $ | 0.57 |
| Distribution Volumetric Rate | $/kWh | 0.0100 |
| Retail Transmission Rate - Network Service Rate (see Note 4) | $/kWh | 0.0103 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate (see Note 5) | $/kWh | 0.0076 |

**The rates set out above do not reflect the impact of the Distribution Rate Protection program on R1 customers per Ontario Regulation 198/17.

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR (see Note 10) | $/kWh | 0.0030 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers (see Note 10) | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) (see Note 10) | $/kWh | 0.0005 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Hydro One Networks Inc.
## TARIFF OF RATES AND CHARGES
### Effective and Implementation Date January 1, 2022
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**EB-2021-0032**

## YEAR-ROUND LOW DENSITY - R2**
### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge* | $ | 128.53 |
| Base Rate Adjustment to Recover Past Tax Amounts - effective until June 30, 2023 | $ | 4.42 |
| Smart Metering Entity Charge - effective until December 31, 2022 | $ | 0.57 |
| Distribution Volumetric Rate | $/kWh | 0.0160 |
| Retail Transmission Rate - Network Service Rate (see Note 4) | $/kWh | 0.0096 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate (see Note 5) | $/kWh | 0.0072 |

*Under the Ontario Energy Board Act, 1998 and associated Regulations, every qualifying year-round customer with a principal residence is eligible to receive Rural or Remote Rate Protection (RRRP). The service charge shown for eligible R2 customers will be reduced by the applicable RRRP credit, currently at $60.50.

**The rates set out above do not reflect the impact of the Distribution Rate Protection program on R2 customers per Ontario Regulation 198/17.

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR (see Note 10) | $/kWh | 0.0030 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers (see Note 10) | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) (see Note 10) | $/kWh | 0.0005 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

## SEASONAL
### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 58.43 |
| Base Rate Adjustment to Recover Past Tax Amounts - effective until June 30, 2023 | $ | 1.79 |
| Smart Metering Entity Charge - effective until December 31, 2022 | $ | 0.57 |
| Distribution Volumetric Rate | $/kWh | 0.0311 |
| Retail Transmission Rate - Network Service Rate (see Note 4) | $/kWh | 0.0081 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate (see Note 5) | $/kWh | 0.0064 |

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR (see Note 10) | $/kWh | 0.0030 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers (see Note 10) | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) (see Note 10) | $/kWh | 0.0005 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Hydro One Networks Inc.
## TARIFF OF RATES AND CHARGES
### Effective and Implementation Date January 1, 2022
**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2021-0032**

## GENERAL SERVICE CLASSIFICATIONS

General Service classification applies to any service that does not fit the description of residential classes. It includes combination type services where a variety of uses are made of the service by the owner of one property, and all multiple services except residential. Class A and Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

Hydro One Networks' General Service area is sub-divided into two density zones according to the following:

- Urban Density Zone is defined as areas containing 3,000 or more customers with a line density of at least 60 customers per circuit kilometer.
- Non-Urban Density Zone is defined as areas other than Urban Density Zone.

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

If included in the following listing of monthly rates and charges, the rate rider for the disposition of WMS - Sub-account CBR Class B is not applicable to wholesale market participants (WMP), customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new Class B customers.

If included in the following listing of monthly rates and charges, the rate rider for the disposition of Global Adjustment is only applicable to non-RPP Class B customers. It is not applicable to WMP, customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new non-RPP Class B customers.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

# Hydro One Networks Inc.
## TARIFF OF RATES AND CHARGES
### Effective and Implementation Date January 1, 2022
**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2021-0032**

## URBAN GENERAL SERVICE ENERGY BILLED - UGe

This classification applies to a non-residential account located in an Urban Density Zone whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW.

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 26.95 |
| Base Rate Adjustment to Recover Past Tax Amounts - effective until June 30, 2023 | $ | 0.81 |
| Smart Metering Entity Charge - effective until December 31, 2022 | $ | 0.57 |
| Distribution Volumetric Rate | $/kWh | 0.0324 |
| Base Rate Adjustment to Recover Past Tax Amounts - effective until June 30, 2023 | $/kWh | 0.0010 |
| Retail Transmission Rate - Network Service Rate (see Note 4) | $/kWh | 0.0087 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate (see Note 5) | $/kWh | 0.0060 |

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR (see Note 10) | $/kWh | 0.0030 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers (see Note 10) | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) (see Note 10) | $/kWh | 0.0005 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

## GENERAL SERVICE ENERGY BILLED - GSe

This classification applies to a non-residential account not located in an Urban Density Zone whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW.

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 34.13 |
| Base Rate Adjustment to Recover Past Tax Amounts - effective until June 30, 2023 | $ | 1.11 |
| Smart Metering Entity Charge - effective until December 31, 2022 | $ | 0.57 |
| Distribution Volumetric Rate | $/kWh | 0.0680 |
| Base Rate Adjustment to Recover Past Tax Amounts - effective until June 30, 2023 | $/kWh | 0.0022 |
| Retail Transmission Rate - Network Service Rate (see Note 4) | $/kWh | 0.0081 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate (see Note 5) | $/kWh | 0.0059 |

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR (see Note 10) | $/kWh | 0.0030 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers (see Note 10) | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) (see Note 10) | $/kWh | 0.0005 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Hydro One Networks Inc.
## TARIFF OF RATES AND CHARGES
### Effective and Implementation Date January 1, 2022
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**EB-2021-0032**

## URBAN GENERAL SERVICE DEMAND BILLED - UGd

This classification applies to a non-residential account located in an Urban Density Zone whose average monthly maximum demand is equal to or greater than, or is forecast to be equal to or greater than, 50 kW. Hydro One establishes billing determinants for demand customers' Distribution charges at the greater of 100 per cent of kW and 90 per cent of kVA where kVA metering is installed. When a customer's power factor is known to be less than 90 per cent, a kVA meter of equivalent electronic meter shall be used for measuring and billing.

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 104.78 |
| Base Rate Adjustment to Recover Past Tax Amounts - effective until June 30, 2023 | $ | 3.92 |
| Distribution Volumetric Rate | $/kW | 11.1722 |
| Base Rate Adjustment to Recover Past Tax Amounts - effective until June 30, 2023 | $/kW | 0.4134 |
| Retail Transmission Rate - Network Service Rate (see Note 4) | $/kW | 3.1157 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate (see Note 5) | $/kW | 2.1682 |

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR (see Note 10) | $/kWh | 0.0030 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers (see Note 10) | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) (see Note 10) | $/kWh | 0.0005 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

## GENERAL SERVICE DEMAND BILLED - GSd

This classification applies to a non-residential account not located in an Urban Density Zone whose average monthly maximum demand is equal to or greater than, or is forecast to be equal to or greater than, 50 kW. Hydro One establishes billing determinants for demand customers' Distribution charges at the greater of 100 per cent of kW and 90 per cent of kVA where kVA metering is installed. When a customer's power factor is known to be less than 90 per cent, a kVA meter or other equivalent electronic meter shall be used for measuring and billing.

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 113.67 |
| Base Rate Adjustment to Recover Past Tax Amounts - effective until June 30, 2023 | $ | 4.34 |
| Distribution Volumetric Rate | $/kW | 19.3834 |
| Base Rate Adjustment to Recover Past Tax Amounts - effective until June 30, 2023 | $/kW | 0.7338 |
| Retail Transmission Rate - Network Service Rate (see Note 4) | $/kW | 2.4058 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate (see Note 5) | $/kW | 1.6886 |

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR (see Note 10) | $/kWh | 0.0030 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers (see Note 10) | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) (see Note 10) | $/kWh | 0.0005 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Hydro One Networks Inc.
## TARIFF OF RATES AND CHARGES
### Effective and Implementation Date January 1, 2022
**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2021-0032**

## DISTRIBUTED GENERATION - DGen

This classification applies to an embedded retail generation facility connected to the distribution system that is not classified as MicroFIT generation. Hydro One establishes billing determinants for demand customers' Distribution charges at the greater of 100 per cent of kW and 90 per cent of kVA where kVA metering is installed. When a customer's power factor is known to be less than 90 per cent, a kVA meter or other equivalent electronic meter shall be used for measuring and billing. Class A and Class B consumers are defined in accordance with O. Reg. 429/04.

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 199.36 |
| Base Rate Adjustment to Recover Past Tax Amounts - effective until June 30, 2023 | $ | 1.74 |
| Distribution Volumetric Rate | $/kW | 11.0093 |
| Base Rate Adjustment to Recover Past Tax Amounts - effective until June 30, 2023 | $/kW | 0.0883 |
| Retail Transmission Rate - Network Service Rate (see Note 4) | $/kW | 1.1695 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate (see Note 5) | $/kW | 0.8226 |

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR (see Note 10) | $/kWh | 0.0030 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers (see Note 10) | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) (see Note 10) | $/kWh | 0.0005 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Hydro One Networks Inc.
## TARIFF OF RATES AND CHARGES
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## SUB TRANSMISSION - ST

This classification applies to either:

- Embedded supply to Local Distribution Companies (LDCs). "Embedded" meaning receiving supply via Hydro One Distribution assets, and where Hydro One is the host distributor to the embedded LDC. Situations where the LDC is supplied via Specific Facilities are included. OR
- Load which:
  - is three-phase; and
  - is directly connected to and supplied from Hydro One Distribution assets between 44 kV and 13.8 kV inclusive; the meaning of "directly includes Hydro One not owning the local transformation; and
  - is greater than 500 kW (monthly measured maximum demand averaged over the most recent calendar year or whose forecasted monthly average demand over twelve consecutive months is greater than 500 kW).

Hydro One establishes billing determinants for demand customers' Distribution charges at the greater of 100 per cent of kW and 90 per cent of kVA where kVA metering is installed. When a customer's power factor is known to be less than 90 per cent, a kVA meter or other equivalent electronic meter shall be used for measuring and billing.

Class A and Class B consumers are defined in accordance with O. Reg. 429/04.

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 612.97 |
| Base Rate Adjustment to Recover Past Tax Amounts - effective until June 30, 2023 | $ | 36.18 |
| Meter Charge (for Hydro One ownership) (see Note 9) | $ | 770.06 |
| Facility Charge for connection to Common ST Lines (44 kV to 13.8 kV) (see Notes 1, 8 and 11) | $/kW | 1.6208 |
| Base Rate Adjustment to Recover Past Tax Amounts - effective until June 30, 2023 | $/kW | 0.0540 |
| Facility Charge for connection to Specific ST Lines (44 kV to 13.8 kV) (see Note 2) | $/km | 626.0882 |
| Facility Charge for connection to high-voltage (> 13.8 kV secondary) delivery High Voltage Distribution Station (see Notes 1 and 11) | $/kW | 2.4058 |
| Facility Charge for connection to low-voltage (< 13.8 kV secondary) delivery High Voltage Distribution Station (see Notes 1 and 11) | $/kW | 4.0946 |
| Facility Charge for connection to low-voltage (< 13.8 kV secondary) Low Voltage Distribution Station (see Notes 3 and 11) | $/kW | 1.6888 |
| Retail Transmission Service Rates (see Notes 6 and 7) | | |
| Retail Transmission Rate - Network Service Rate (see Note 4) | $/kW | 4.3473 |
| Retail Transmission Rate - Line Connection Service Rate (see Note 5) | $/kW | 0.6788 |
| Retail Transmission Rate - Transformation Connection Service Rate (see Note 5) | $/kW | 2.3267 |

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR (see Note 10) | $/kWh | 0.0030 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers (see Note 10) | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) (see Note 10) | $/kWh | 0.0005 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Hydro One Networks Inc.
## TARIFF OF RATES AND CHARGES
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## UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

This classification applies to an account taking electricity at 750 volts or less whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW and the consumption is unmetered. The amount of electricity consumed by unmetered connections will be based on detailed information/documentation provided by the device's manufacturer and will be agreed to by Hydro One and the customer and may be subject to periodic monitoring of actual consumption. Eligible unmetered loads include cable TV amplifiers, bus shelters, telephone booths, railway crossings and other small fixed loads. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor’s Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 39.80 |
| Base Rate Adjustment to Recover Past Tax Amounts - effective until June 30, 2023 | $ | 0.89 |
| Distribution Volumetric Rate | $/kWh | 0.0265 |
| Base Rate Adjustment to Recover Past Tax Amounts - effective until June 30, 2023 | $/kWh | 0.0006 |
| Retail Transmission Rate - Network Service Rate (see Note 4) | $/kWh | 0.0068 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate (see Note 5) | $/kWh | 0.0049 |

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR (see Note 10) | $/kWh | 0.0030 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers (see Note 10) | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) (see Note 10) | $/kWh | 0.0005 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Hydro One Networks Inc.
## TARIFF OF RATES AND CHARGES
### Effective and Implementation Date January 1, 2022
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## SENTINEL LIGHTING SERVICE CLASSIFICATION

This classification is applicable to all Hydro One Networks' customers who have separate service to a sentinel light. The energy consumption for sentinel lights is estimated based on Networks' profile for sentinel lighting load, which provides the amount of time each month that the sentinel lights are operating. Class B consumers are defined in accordance to O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, in should be noted that the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 3.20 |
| Base Rate Adjustment to Recover Past Tax Amounts - effective until June 30, 2023 | $ | 0.14 |
| Distribution Volumetric Rate | $/kWh | 0.1737 |
| Base Rate Adjustment to Recover Past Tax Amounts - effective until June 30, 2023 | $/kWh | 0.0078 |
| Retail Transmission Rate - Network Service Rate (see Note 4) | $/kWh | 0.0068 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate (see Note 5) | $/kWh | 0.0039 |

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR (see Note 10) | $/kWh | 0.0030 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers (see Note 10) | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) (see Note 10) | $/kWh | 0.0005 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Hydro One Networks Inc.
## TARIFF OF RATES AND CHARGES
### Effective and Implementation Date January 1, 2022
**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2021-0032**

## STREET LIGHTING SERVICE CLASSIFICATION

This classification is applicable to all Hydro One Networks' customers who have streetlights, which are devices owned by or operated for a road authority and/or municipal corporation. The energy consumption for street lights is estimated based on Networks' profile for street lighting load, which provides the amount of time each month that the street lights are operating. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor’s Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, it should be noted that the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 3.71 |
| Base Rate Adjustment to Recover Past Tax Amounts - effective until June 30, 2023 | $ | 0.11 |
| Distribution Volumetric Rate | $/kWh | 0.1134 |
| Base Rate Adjustment to Recover Past Tax Amounts - effective until June 30, 2023 | $/kWh | 0.0034 |
| Retail Transmission Rate - Network Service Rate (see Note 4) | $/kWh | 0.0067 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate (see Note 5) | $/kWh | 0.0038 |

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR (see Note 10) | $/kWh | 0.0030 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers (see Note 10) | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) (see Note 10) | $/kWh | 0.0005 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Hydro One Networks Inc.
## TARIFF OF RATES AND CHARGES
### Effective and Implementation Date January 1, 2022
**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2021-0032**

## microFIT SERVICE CLASSIFICATION

This classification applies to an electricity generation facility contracted under the Independent Electricity System Operator's microFIT program and connected to the distributor's distribution system. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 4.55 |

# Hydro One Networks Inc.
## TARIFF OF RATES AND CHARGES
### Effective and Implementation Date January 1, 2022
**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2021-0032**

## ALLOWANCES

### CUSTOMER-SUPPLIED TRANSFORMATION ALLOWANCE
Applicable to customers providing their own transformers and the primary voltage is under 50 kV

| | | |
|---|---|---|
| Demand Billed - per kW of billing demand/month | $/kW | (0.60) |
| Energy Billed - per kWh of billing energy/month | $/kWh | (0.0014) |

### TRANFORMER LOSS ALLOWANCE
Applicable to non-ST customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side).

| | | |
|---|---|---|
| For installations up to and including bank capacity of 400 kVA | % | (1.50) |
| For bank capacities over 400 kVA | % | (1.00) |

Applicable to ST customers requiring a billing adjustment for transformer losses as the result of being metered on the secondary side of a transformer. The uniform value of 1% shall be added to measured demand and energy (as measured on the secondary side) to adjust for transformer losses.

Alternately, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly.

For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities.

## LOSS FACTORS

| | |
|---|---|
| Residential - UR | 1.057 |
| Residential - R1 | 1.076 |
| Residential - R2 | 1.105 |
| Residential - Seasonal | 1.104 |
| General Service - UGe | 1.067 |
| General Service - GSe | 1.096 |
| General Service - UGd | 1.050 |
| General Service - GSd | 1.061 |
| Distributed Generation - Dgen | 1.061 |
| Unmetered Scattered Load | 1.092 |
| Sentinel Lights | 1.092 |
| Street Lights | 1.092 |
| | |
| Sub Transmission - ST | |
| Distribution Loss Factors | |
| Embedded Delivery Points (metering at station) | 1.000 |
| Embedded Delivery Points (metering away from station) | 1.028 |
| Total Loss Factors | |
| Embedded Delivery Points (metering at station) | 1.006 |
| Embedded Delivery Points (metering away from station) | 1.034 |

# Hydro One Networks Inc.
## TARIFF OF RATES AND CHARGES
### Effective and Implementation Date January 1, 2022
**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2021-0032**

## SPECIFIC SERVICE CHARGES

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

### Customer Administration

| | | |
|---|---|---|
| Easement letter - letter request | $ | 92.51 |
| Easement letter - web request | $ | 25.00 |
| Returned cheque charge | $ | 7.00 |
| Account set up charge/change of occupancy charge (plus credit agency costs, if applicable) | $ | 38.00 |
| Special meter reads (retailer requested off-cycle read) | $ | 90.00 |
| Meter dispute charge plus Measurement Canada fees (if meter found correct) | $ | 30.00 |

### Non-Payment of Account

| | | |
|---|---|---|
| Late payment - per month (effective annual rate 19.56% per annum or 0.04896% compounded daily rate) | % | 1.50 |
| Collection - reconnect at meter - during regular hours | $ | 65.00 |
| Collection - reconnect at meter - after regular hours | $ | 185.00 |
| Collection - reconnect at pole - during regular hours | $ | 185.00 |
| Collection - reconnect at pole - after regular hours | $ | 415.00 |

### Other

| | | |
|---|---|---|
| Service call - customer owned equipment - during regular hours | $ | 210.00* |
| Service call - customer owned equipment - after regular hours | $ | 775.00* |
| Temporary service install & remove - overhead - no transformer | $ | Actual Costs |
| Temporary service install & remove - underground - no transformer | $ | Actual Costs |
| Temporary service install & remove - overhead - with transformer | $ | Actual Costs |
| Specific charge for access to power poles - telecom | $ | 44.50 |
| Reconnect completed after regular hours (customer/contract driven) - at meter | $ | 245.00 |
| Reconnect completed after regular hours (customer/contract) driven) - at pole | $ | 475.00 |
| Additional service layout fee - basic/complex (more than one hour) | $ | 595.20 |
| Pipeline crossings | $ | 2,499.29 |
| Water crossings | $ | 3,717.21 |
| Railway crossings | $ | $4,965.66 plus Railway Feedthrough Costs |

# Hydro One Networks Inc.
## TARIFF OF RATES AND CHARGES
### Effective and Implementation Date January 1, 2022
**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2021-0032**

| | | |
|---|---|---|
| Overhead line staking per meter | $ | 4.42 |
| Underground line staking per meter | $ | 3.18 |
| Subcable line staking per meter | $ | 2.78 |
| Central metering - new service <45 kw | $ | 100.00 |
| Conversion to central metering <45 kw | $ | 1,612.75 |
| Conversion to central metering >=45 kw | $ | 1,512.75 |
| Connection impact assessments - net metering | $ | 3,329.86 |
| Connection impact assessments - embedded LDC generators | $ | 2,996.97 |
| Connection impact assessments - small projects <= 500 kw | $ | 3,405.38 |
| Connection impact assessments - small projects <= 500 kw, simplified | $ | 2,054.41 |
| Connection impact assessments - greater than capacity allocation exempt projects - capacity allocation required projects | $ | 9,011.83 |
| Connection impact assessments - greater than capacity allocation exempt projects - TS review for LDC capacity allocation required projects | $ | 5,969.89 |
| Specific charge for access to power poles - LDC | $ | see below |
| Specific charge for access to power poles - generators | $ | see below |
| Specific charge for access to power poles - municipal streetlights | $ | 2.04 |
| Sentinel light rental charge | $ | 10.00 |
| Sentinel light pole rental charge | $ | 7.00 |

*Base Charge only. Additional work on equipment will be based on actual costs.

Specific Charge for LDCs Access to the Power Poles ($/pole/year)

| | | |
|---|---|---|
| LDC rate for 10’ of power space | $ | 90.60 |
| LDC rate for 15’ of power space | $ | 108.72 |
| LDC rate for 20’ of power space | $ | 120.80 |
| LDC rate for 25’ of power space | $ | 129.43 |
| LDC rate for 30’ of power space | $ | 135.90 |
| LDC rate for 35’ of power space | $ | 140.93 |
| LDC rate for 40’ of power space | $ | 144.96 |
| LDC rate for 45’ of power space | $ | 148.25 |
| LDC rate for 50’ of power space | $ | 151.00 |
| LDC rate for 55’ of power space | $ | 153.32 |
| LDC rate for 60’ of power space | $ | 155.31 |

Specific Charge for Generator Access to the Power Poles ($/pole/year)

| | | |
|---|---|---|
| Generator rate for 10’ of power space | $ | 90.60 |
| Generator rate for 15’ of power space | $ | 108.72 |
| Generator rate for 20’ of power space | $ | 120.80 |
| Generator rate for 25’ of power space | $ | 129.43 |
| Generator rate for 30’ of power space | $ | 135.90 |
| Generator rate for 35’ of power space | $ | 140.93 |
| Generator rate for 40’ of power space | $ | 144.96 |
| Generator rate for 45’ of power space | $ | 148.25 |
| Generator rate for 50’ of power space | $ | 151.00 |
| Generator rate for 55’ of power space | $ | 153.32 |
| Generator rate for 60’ of power space | $ | 155.31 |

# Hydro One Networks Inc.
## TARIFF OF RATES AND CHARGES
### Effective and Implementation Date January 1, 2022
**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2021-0032**

## RETAIL SERVICE CHARGES (if applicable)

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

Retail Service Charges refer to services provided by a distributor to retailers or customers related to the supply of competitive electricity.

| | | |
|---|---|---|
| One-time charge, per retailer, to establish the service agreement between the distributor and the retailer | $ | 107.68 |
| Monthly fixed charge, per retailer | $ | 43.08 |
| Monthly variable charge, per customer, per retailer | $/cust. | 1.07 |
| Distributor-consolidated billing monthly charge, per customer, per retailer | $/cust. | 0.64 |
| Retailer-consolidated billing monthly credit, per customer, per retailer | $/cust. | (0.64) |
| Service Transaction Requests (STR) | | |
| Request fee, per request, applied to the requesting party | $ | 0.54 |
| Processing fee, per request, applied to the requesting party | $ | 1.07 |
| Request for customer information as outlined in Section 10.6.3 and Chapter 11 of the Retail Settlement Code directly to retailers and customers, if not delivered electronically through the Electronic Business Transaction (EBT) system, applied to the requesting party | | |
| Up to twice a year | | no charge |
| More than twice a year, per request (plus incremental delivery costs) | $ | 4.31 |
| Notice of switch letter charge, per letter (unless the distributor has opted out of applying the charge as per the Ontario Energy Board's Decision and Order EB-2015-0304, issued on February 14, 2019) | $ | 2.15 |

# Hydro One Networks Inc.
## TARIFF OF RATES AND CHARGES
### Effective and Implementation Date January 1, 2022
**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2021-0032**

**NOTES**

1. The basis of the charge is the customer's monthly maximum demand. For an ST customer with multiple delivery points served from the same Transformer Station or High Voltage Distribution Station, the aggregated demand will be the applicable billing determinant. Demand is not aggregated between stations.
2. The basis of the charge is kilometers of line, within the supplied LDC's service area, supplying solely that LDC.
3. The basis of the charge is the "non-coincident demand" at each delivery point of the customer supplied by the station. This is measured as the kW demand at the delivery point at the time in the month of maximum load on the delivery point. For a customer connected through two or more distribution stations, the total charge for the connection to the shared distribution stations is the sum of the relevant charges for each of the distribution stations.
4. The monthly billing determinant for the RTSR Network Service rate is:
   a. For energy-only metered customers: the customer's metered energy consumption adjusted by the total loss factor as approved by the Ontario Energy Board.
   b. For interval-metered customers: the peak demand from 7 AM to 7 PM (local time) on IESO business days in the billing period. The rates shown are to be adjusted by the total loss factor as approved by the Ontario Energy Board.
   c. For non-interval-metered demand billed customers: the non-coincident peak demand in the billing period. The rates shown are to be adjusted by the total loss factor as approved by the Ontario Energy Board.
5. The monthly billing determinant for the RTSR Line and Transformation Connection Service rates:
   a. For energy-only metered customers: the customer's metered energy consumption adjusted by the total loss factor as approved by the Ontario Energy Board.
   b. For all demand billed customers: the non-coincident peak demand in the billing period. The rates shown are to be adjusted by the total loss factor as approved by the Ontario Energy Board.
   c. For customers with load displacement generation above 1 MW, or 2 MW for renewable generation, installed after October 1998, RTSR connection is billed at the gross demand level.
6. Delivery point with respect to RTSR is defined as the low side of the Transformer Station that steps down voltage from above 50 kV to below 50 kV. For customer with multiple interval-metered delivery points served from the same Transformer Station, the aggregated demand at the said delivery points on the low side of the Transformer Station will be the applicable billing determinant.
7. The loss factors, and which connection service rates are applied, are determined based on the point at which the distribution utility or customer is metered for its connection to Hydro One Distribution's system. Hydro One Distribution's connection agreements with these distribution utilities and customers will establish the appropriate loss factors and connection rates to apply from Hydro One Distribution's tariff schedules.
8. The Common ST Lines rate also applies to Distributors which use lines in the 12.5 kV to 4.16 kV range from HVDSs or LVDSs.
9. The Meter charge is applied per metering facility at delivery points for which Hydro One owns the metering.
10. The Wholesale Market Service Rate and the Rural or Remote Electricity Rate Protection Charge are applied solely to non-Wholesale Market Participants. For Class A customers, distributors shall bill the actual CBDR costs to Class A customers in proportion to their contribution to peak. These rates pertain to the IESO's defined point of sale; consequently, appropriate loss factors as approved by the Ontario Energy Board must be applied to the customers metered energy.
11. For customers with load displacement generation at 1MW or above, or 2MW or above for renewable generation, installed after October 1998, the ST volumetric charges are billed at the gross demand level.

# SCHEDULE A

# APPROVED 2022 TARIFF OF RATES AND CHARGES

# DECISION AND RATE ORDER

# HYDRO ONE NETWORKS INC.

# EB-2021-0033

# JANUARY 27, 2022

# Hydro One Networks Inc.
# Former Norfolk Power Distribution Inc. Service Area
## TARIFF OF RATES AND CHARGES
### Effective Date January 1, 2022
### Implementation Date February 1, 2022
**This schedule supersedes and replaces all previously**
**approved schedules of Rates, Charges and Loss Factors**

**EB-2021-0033**

## RESIDENTIAL SERVICE CLASSIFICATION

This classification applies to an account taking electricity at 750 volts or less where the electricity is used exclusively in a separate metered living accommodation. Customers shall be residing in single-dwelling units that consist of a detached house or one unit of a semi-detached, duplex, triplex or quadruplex house, with a residential zoning. Separately metered dwellings within a town house complex or apartment building also qualify as residential customers. All customers are single-phase. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 39.10 |
| Rate Rider for Recovery of Foregone Revenue - effective until December 31, 2022 | $ | 0.10 |
| Rate Rider for Disposition of Group 2 Accounts (Excluding LRAMVA) - effective until December 31, 2022 | $ | (0.14) |
| Smart Metering Entity Charge - effective until December 31, 2022 | $ | 0.57 |
| Low Voltage Service Rate | $/kWh | 0.0009 |
| Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2022) - effective until December 31, 2023 | $/kWh | 0.0004 |
| Rate Rider for Application of Tax Change - in effect until the effective date of the next Cost of Service Based Rate Order | $/kWh | 0.0002 |
| Retail Transmission Rate - Network Service Rate | $/kWh | 0.0072 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kWh | 0.0041 |

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR | $/kWh | 0.0030 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0005 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Hydro One Networks Inc.
# Former Norfolk Power Distribution Inc. Service Area
## TARIFF OF RATES AND CHARGES
### Effective Date January 1, 2022
### Implementation Date February 1, 2022
**This schedule supersedes and replaces all previously**
**approved schedules of Rates, Charges and Loss Factors**

**EB-2021-0033**

## GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION

This classification applies to a non residential account taking electricity at 750 volts or less whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 53.11 |
| Rate Rider for Recovery of Foregone Revenue - effective until December 31, 2022 | $ | 0.13 |
| Smart Metering Entity Charge - effective until December 31, 2022 | $ | 0.57 |
| Distribution Volumetric Rate | $/kWh | 0.0166 |
| Low Voltage Service Rate | $/kWh | 0.0008 |
| Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2022) - effective until December 31, 2023 | $/kWh | 0.0081 |
| Rate Rider for Application of Tax Change - in effect until the effective date of the next Cost of Service based Rate Order | $/kWh | 0.0001 |
| Rate Rider for Disposition of Group 2 Accounts (Excluding LRAMVA) - effective until December 31, 2022 | $/kWh | -0.0001 |
| Retail Transmission Rate - Network Service Rate | $/kWh | 0.0067 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kWh | 0.0034 |

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR | $/kWh | 0.0030 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0005 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Hydro One Networks Inc.
# Former Norfolk Power Distribution Inc. Service Area
## TARIFF OF RATES AND CHARGES
### Effective Date January 1, 2022
### Implementation Date February 1, 2022
**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2021-0033**

## GENERAL SERVICE 50 TO 4,999 KW SERVICE CLASSIFICATION

This classification applies to a non residential account whose average monthly maximum demand used for billing purposes is equal to or greater than, or is forecast to be equal to or greater than, 50 kW but less than 5,000 kW. Class A and Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

If included in the following listing of monthly rates and charges, the rate rider for the disposition of WMS - Sub-account CBR Class B is not applicable to wholesale market participants (WMP), customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new Class B customers.

If included in the following listing of monthly rates and charges, the rate rider for the disposition of Global Adjustment is only applicable to non-RPP Class B customers. It is not applicable to WMP, customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new non-RPP Class B customers.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 260.95 |
| Rate Rider for Recovery of Foregone Revenue - effective until December 31, 2022 | $ | 0.66 |
| Distribution Volumetric Rate | $/kW | 4.2086 |
| Low Voltage Service Rate | $/kW | 0.3050 |
| Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2022) - effective until December 31, 2023 | $/kW | 0.2853 |
| Rate Rider for Application of Tax Change - in effect until the effective date of the next Cost of Service based Rate Order | $/kW | 0.0211 |
| Rate Rider for Disposition of Group 2 Accounts (Excluding LRAMVA) - effective until December 31, 2022 | $/kW | (0.0203) |

Issued - January 27, 2022

# Hydro One Networks Inc.
# Former Norfolk Power Distribution Inc. Service Area
## TARIFF OF RATES AND CHARGES
### Effective Date January 1, 2022
### Implementation Date February 1, 2022
**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2021-0033**

| | | |
|---|---|---|
| Rate Rider for Recovery of Foregone Revenue - effective until December 31, 2022 | $/kW | 0.0121 |
| Retail Transmission Rate - Network Service Rate | $/kW | 2.7046 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kW | 1.3772 |

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR | $/kWh | 0.0030 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0005 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Hydro One Networks Inc.
# Former Norfolk Power Distribution Inc. Service Area
## TARIFF OF RATES AND CHARGES
### Effective Date January 1, 2022
### Implementation Date February 1, 2022
**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2021-0033**

## UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

This classification applies to an account taking electricity at 750 volts or less whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW and the consumption is unmetered. Such connections include cable TV power packs, bus shelters, telephone booths, traffic lights, railway crossings, etc. The level of the consumption will be agreed to by the distributor and the customer, based on detailed manufacturer information/ documentation with regard to electrical consumption of the unmetered load or periodic monitoring of actual consumption. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

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It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 16.47 |
| Rate Rider for Recovery of Foregone Revenue - effective until December 31, 2022 | $ | 0.04 |
| Distribution Volumetric Rate | $/kWh | 0.0093 |
| Low Voltage Service Rate | $/kWh | 0.0008 |
| Rate Rider for Application of Tax Change - in effect until the effective date of the next Cost of Service based Rate Order | $/kWh | 0.0002 |
| Rate Rider for Disposition of Group 2 Accounts (Excluding LRAMVA) - effective until December 31, 2022 | $/kWh | -0.0001 |
| Retail Transmission Rate - Network Service Rate | $/kWh | 0.0067 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kWh | 0.0034 |

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR | $/kWh | 0.0030 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0005 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Hydro One Networks Inc.
# Former Norfolk Power Distribution Inc. Service Area
## TARIFF OF RATES AND CHARGES
### Effective Date January 1, 2022
### Implementation Date February 1, 2022
**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2021-0033**

## SENTINEL LIGHTING SERVICE CLASSIFICATION

This classification refers to accounts that are unmetered lighting load supplied to a sentinel light. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 6.94 |
| Rate Rider for Recovery of Foregone Revenue - effective until December 31, 2022 | $ | 0.02 |
| Distribution Volumetric Rate | $/kW | 20.6518 |
| Low Voltage Service Rate | $/kW | 0.2407 |
| Rate Rider for Application of Tax Change - in effect until the effective date of the next Cost of Service based Rate Order | $/kW | 0.2079 |
| Rate Rider for Disposition of Group 2 Accounts (Excluding LRAMVA) - effective until December 31, 2022 | $/kW | (0.1921) |
| Rate Rider for Recovery of Foregone Revenue - effective until December 31, 2022 | $/kW | 0.0464 |
| Retail Transmission Rate - Network Service Rate | $/kW | 2.0502 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kW | 1.0868 |

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR | $/kWh | 0.0030 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0005 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Hydro One Networks Inc.
# Former Norfolk Power Distribution Inc. Service Area
## TARIFF OF RATES AND CHARGES
### Effective Date January 1, 2022
### Implementation Date February 1, 2022
**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2021-0033**

## STREET LIGHTING SERVICE CLASSIFICATION

This classification applies to an account for roadway lighting with a Municipality, Regional Municipality, Ministry of Transportation and private roadway lighting, controlled by photo cells. The consumption for these customers will be based on the calculated connected load times the required lighting times established in the approved Ontario Energy Board street lighting load shape template. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge (per connection) | $ | 2.10 |
| Rate Rider for Recovery of Foregone Revenue - effective until December 31, 2022 | $ | 0.01 |
| Distribution Volumetric Rate | $/kW | 7.8927 |
| Low Voltage Service Rate | $/kW | 0.2358 |
| Rate Rider for Application of Tax Change - in effect until the effective date of the next Cost of Service based Rate Order | $/kW | 0.0655 |
| Rate Rider for Disposition of Group 2 Accounts (Excluding LRAMVA) - effective until December 31, 2022 | $/kW | (0.0946) |
| Rate Rider for Recovery of Foregone Revenue - effective until December 31, 2022 | $/kW | 0.0332 |
| Retail Transmission Rate - Network Service Rate | $/kW | 2.0398 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kW | 1.0647 |

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR | $/kWh | 0.0030 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0005 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Hydro One Networks Inc.
# Former Norfolk Power Distribution Inc. Service Area
## TARIFF OF RATES AND CHARGES
### Effective Date January 1, 2022
### Implementation Date February 1, 2022
**This schedule supersedes and replaces all previously**
**approved schedules of Rates, Charges and Loss Factors**

**EB-2021-0033**

## EMBEDDED DISTRIBUTOR SERVICE CLASSIFICATION

This classification applies to an electricity distributor licensed by the Ontario Energy Board, and provided electricity by means of Norfolk Power Distribution Inc.'s distribution facilities. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge (per connection) | $ | 655.55 |

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR | $/kWh | 0.0030 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0005 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Hydro One Networks Inc.
# Former Norfolk Power Distribution Inc. Service Area
## TARIFF OF RATES AND CHARGES
### Effective Date January 1, 2022
### Implementation Date February 1, 2022
**This schedule supersedes and replaces all previously**

**approved schedules of Rates, Charges and Loss Factors**

**EB-2021-0033**

## microFIT SERVICE CLASSIFICATION

This classification applies to an electricity generation facility contracted under the Independent Electricity System Operator's microFIT program and connected to the distributor's distribution system. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 4.55 |

Issued - January 27, 2022

# Hydro One Networks Inc.
# Former Norfolk Power Distribution Inc. Service Area
## TARIFF OF RATES AND CHARGES
### Effective Date January 1, 2022
### Implementation Date February 1, 2022
**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2021-0033**

## ALLOWANCES

| | | |
|---|---|---|
| Transformer Allowance for Ownership - per kW of billing demand/month | $/kW | (0.60) |
| Primary Metering Allowance for Transformer Losses - applied to measured demand & energy | % | (1.00) |

## SPECIFIC SERVICE CHARGES

**APPLICATION**

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

### Customer Administration

| | | |
|---|---|---|
| Arrears certificate | $ | 15.00 |
| Statement of account | $ | 15.00 |
| Pulling post-dated cheques | $ | 15.00 |
| Duplicate invoices for previous billing | $ | 15.00 |
| Request for other billing information | $ | 15.00 |
| Easement Letter | $ | 15.00 |
| Income tax letter | $ | 15.00 |
| Notification charge | $ | 15.00 |
| Account history | $ | 15.00 |
| Credit reference/credit check (plus credit agency costs) | $ | 15.00 |
| Returned cheque (plus bank charges) | $ | 15.00 |
| Charge to certify cheque | $ | 15.00 |
| Legal letter charge | $ | 15.00 |
| Account set up charge / change of occupancy charge (plus credit agency costs if applicable) | $ | 30.00 |
| Special meter reads | $ | 30.00 |
| Meter dispute charge plus Measurement Canada fees (if meter found correct) | $ | 30.00 |

### Non-Payment of Account

| | | |
|---|---|---|
| Late payment - per month<br>(effective annual rate 19.56% per annum or 0.04896% compounded daily rate) | % | 1.50 |
| Reconnection at meter - during regular hours | $ | 65.00 |
| Reconnection at meter - after regular hours | $ | 185.00 |
| Reconnection at pole - during regular hours | $ | 185.00 |
| Reconnection at pole - after regular hours | $ | 415.00 |

# Hydro One Networks Inc.
# Former Norfolk Power Distribution Inc. Service Area
## TARIFF OF RATES AND CHARGES
### Effective Date January 1, 2022
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**EB-2021-0033**

### Other

| | | |
|---|---|---|
| Service call - customer owned equipment | $ | 30.00 |
| Service call - after regular hours | $ | 165.00 |
| Specific charge for access to the power poles - $/pole/year (with the exception of wireless attachments) | $ | 34.76 |

# Hydro One Networks Inc.
# Former Norfolk Power Distribution Inc. Service Area
## TARIFF OF RATES AND CHARGES
### Effective Date January 1, 2022
### Implementation Date February 1, 2022
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**EB-2021-0033**

## RETAIL SERVICE CHARGES (if applicable)

**APPLICATION**

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

Retail Service Charges refer to services provided by a distributor to retailers or customers related to the supply of competitive electricity.

| | | |
|---|---|---|
| One-time charge, per retailer, to establish the service agreement between the distributor and the retailer | $ | 107.68 |
| Monthly fixed charge, per retailer | $ | 43.08 |
| Monthly variable charge, per customer, per retailer | $/cust. | 1.07 |
| Distributor-consolidated billing monthly charge, per customer, per retailer | $/cust. | 0.64 |
| Retailer-consolidated billing monthly credit, per customer, per retailer | $/cust. | -0.64 |
| Service Transaction Requests (STR) | | |
| Request fee, per request, applied to the requesting party | $ | 0.54 |
| Processing fee, per request, applied to the requesting party | $ | 1.07 |
| Request for customer information as outlined in Section 10.6.3 and Chapter 11 of the Retail Settlement Code directly to retailers and customers, if not delivered electronically through the Electronic Business Transaction (EBT) system, applied to the requesting party | | |
| Up to twice a year | | no charge |
| More than twice a year, per request (plus incremental delivery costs) | $ | 4.31 |
| Notice of switch letter charge, per letter (unless the distributor has opted out of applying the charge as per the Ontario Energy Board's Decision and Order EB-2015-0304, issued on February 14, 2019) | $ | 2.15 |

## LOSS FACTORS

If the distributor is not capable of prorating changed loss factors jointly with distribution rates, the revised loss factors will be implemented upon the first subsequent billing for each billing cycle.

| | |
|---|---|
| Total Loss Factor - Secondary Metered Customer < 5,000 kW | 1.0564 |
| Total Loss Factor - Secondary Metered Customer > 5,000 kW | 1.0564 |
| Total Loss Factor - Primary Metered Customer < 5,000 kW | 1.0464 |
| Total Loss Factor - Primary Metered Customer > 5,000 kW | 1.0464 |

# Hydro One Networks Inc.

## Former Haldimand County Hydro Inc. Service Area

## TARIFF OF RATES AND CHARGES

### Effective Date January 1, 2022

### Implementation Date February 1, 2022

**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2021-0033**

## RESIDENTIAL SERVICE CLASSIFICATION

This classification applies to a customer's main place of abode and may include additional buildings served through the same meter, provided they are not rental income units. Residential includes Urban, Suburban and Farm customer's premises which can be occupied on a year-round and seasonal basis. Farm applies to properties actively engaged in agricultural production as defined by Statistics Canada. These premises must be supplied from a single phase primary line. The farm definition does not include tree, sod, or pet farms. Services to year-round pumping stations or other ancillary services remote from the main farm shall be classed as farm. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 37.31 |
| Rate Rider for Recovery of Foregone Revenue - effective until December 31, 2022 | $ | 0.09 |
| Rate Rider for Disposition of Group 2 Accounts (Excluding LRAMVA) - effective until December 31, 2022 | $ | (0.83) |
| Smart Metering Entity Charge - effective until December 31, 2022 | $ | 0.57 |
| Low Voltage Service Rate | $/kWh | 0.0004 |
| Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2022) - effective until December 31, 2023 | $/kWh | 0.0003 |
| Funding Adder for Renewable Energy Generation - in effect until the effective date of the next cost of service based rate order | $/kWh | 0.0002 |
| Retail Transmission Rate - Network Service Rate | $/kWh | 0.0069 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kWh | 0.0061 |

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR | $/kWh | 0.0030 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0005 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Hydro One Networks Inc.

## Former Haldimand County Hydro Inc. Service Area

## TARIFF OF RATES AND CHARGES

### Effective Date January 1, 2022

### Implementation Date February 1, 2022

**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2021-0033**

## GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION

General Service does include farms supplied from polyphase primary lines. General Service includes commercial, industrial, educational, administrative, auxiliary and government services. It also includes combination services where a variety of uses are made of the service by the owner of one property. This classification applies to a non-residential account whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 28.19 |
| Rate Rider for Recovery of Foregone Revenue - effective until December 31, 2022 | $ | 0.07 |
| Smart Metering Entity Charge - effective until December 31, 2022 | $ | 0.57 |
| Distribution Volumetric Rate | $/kWh | 0.0199 |
| Low Voltage Service Rate | $/kWh | 0.0004 |
| Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2022) - effective until December 31, 2023 | $/kWh | (0.0002) |
| Funding Adder for Renewable Energy Generation - in effect until the effective date of the next cost of service based rate order | $/kWh | 0.0002 |
| Rate Rider for Disposition of Group 2 Accounts (Excluding LRAMVA) - effective until December 31, 2022 | $/kWh | (0.0007) |
| Rate Rider for Recovery of Foregone Revenue - effective until December 31, 2022 | $/kWh | 0.0001 |
| Retail Transmission Rate - Network Service Rate | $/kWh | 0.0063 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kWh | 0.0057 |

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR | $/kWh | 0.0030 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0005 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Hydro One Networks Inc.

## Former Haldimand County Hydro Inc. Service Area

## TARIFF OF RATES AND CHARGES

### Effective Date January 1, 2022

### Implementation Date February 1, 2022

**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2021-0033**

## GENERAL SERVICE 50 TO 4,999 KW SERVICE CLASSIFICATION

General Service does include farms supplied from polyphase primary lines. General Service includes commercial, industrial, educational, administrative, auxiliary and government services. It also includes combination services where a variety of uses are made of the service by the owner of one property. This classification applies to a non-residential account whose average monthly maximum demand used for billing purposes is equal to or greater than, or is forecast to be equal to or greater than, 50 kW but less than 5,000 kW. Class A and Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

If included in the following listing of monthly rates and charges, the rate rider for the disposition of WMS - Sub-account CBR Class B is not applicable to wholesale market participants (WMP), customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new Class B customers.

If included in the following listing of monthly rates and charges, the rate rider for the disposition of Global Adjustment is only applicable to non-RPP Class B customers. It is not applicable to WMP, customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new non-RPP Class B customers.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

# Hydro One Networks Inc.
## Former Haldimand County Hydro Inc. Service Area
## TARIFF OF RATES AND CHARGES
### Effective Date January 1, 2022
### Implementation Date February 1, 2022
**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2021-0033**

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 87.49 |
| Rate Rider for Recovery of Foregone Revenue - effective until December 31, 2022 | $ | 0.22 |
| Distribution Volumetric Rate | $/kW | 4.1168 |
| Low Voltage Service Rate | $/kW | 0.1550 |
| Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2022) - effective until December 31, 2023 | $/kW | (0.0575) |
| Funding Adder for Renewable Energy Generation - in effect until the effective date of the next cost of service based rate order | $/kW | 0.0195 |
| Rate Rider for Disposition of Group 2 Accounts (Excluding LRAMVA) - effective until December 31, 2022 | $/kW | (0.1031) |
| Rate Rider for Recovery of Foregone Revenue - effective until December 31, 2022 | $/kW | 0.0121 |
| Retail Transmission Rate - Network Service Rate | $/kW | 2.6512 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kW | 2.4073 |

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR | $/kWh | 0.0030 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0005 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Hydro One Networks Inc.
## Former Haldimand County Hydro Inc. Service Area
## TARIFF OF RATES AND CHARGES
### Effective Date January 1, 2022
### Implementation Date February 1, 2022
**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2021-0033**

# UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

This classification applies to an account taking electricity at 750 volts or less whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW and the consumption is unmetered. Such connections include cable TV power packs, bus shelters, telephone booths, traffic lights, railway crossings, etc. The level of the consumption will be agreed to by the distributor and the customer, based on detailed manufacturer information/ documentation with regard to electrical consumption of the unmetered load or periodic monitoring of actual consumption. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor’s Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor’s Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge (per connection) | $ | 20.42 |
| Rate Rider for Recovery of Foregone Revenue - effective until December 31, 2022 | $ | 0.05 |
| Distribution Volumetric Rate | $/kWh | 0.0026 |
| Low Voltage Service Rate | $/kWh | 0.0004 |
| Funding Adder for Renewable Energy Generation - in effect until the effective date of the next cost of service based rate order | $/kWh | 0.0002 |
| Rate Rider for Disposition of Group 2 Accounts (Excluding LRAMVA) - effective until December 31, 2022 | $/kWh | -0.0010 |
| Retail Transmission Rate - Network Service Rate | $/kWh | 0.0063 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kWh | 0.0057 |

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR | $/kWh | 0.0030 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0005 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Hydro One Networks Inc.

## Former Haldimand County Hydro Inc. Service Area

## TARIFF OF RATES AND CHARGES

### Effective Date January 1, 2022

### Implementation Date February 1, 2022

**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2021-0033**

## SENTINEL LIGHTING SERVICE CLASSIFICATION

This classification refers to an account that is an unmetered lighting load supplied to a sentinel light. (Metered sentinel lighting is captured under the consumption of the principal service.) The consumption for these customers is assumed to have the same hourly consumption load profile as for Street Lighting. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge (per connection) | $ | 14.89 |
| Rate Rider for Recovery of Foregone Revenue - effective until December 31, 2022 | $ | 0.04 |
| Distribution Volumetric Rate | $/kW | 38.4338 |
| Low Voltage Service Rate | $/kW | 0.1099 |
| Funding Adder for Renewable Energy Generation - in effect until the effective date of the next cost of service based rate order | $/kW | 0.6224 |
| Rate Rider for Disposition of Group 2 Accounts (Excluding LRAMVA) - effective until December 31, 2022 | $/kW | (1.0258) |
| Rate Rider for Recovery of Foregone Revenue - effective until December 31, 2022 | $/kW | 0.0788 |
| Retail Transmission Rate - Network Service Rate | $/kW | 1.9246 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kW | 1.7655 |

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR | $/kWh | 0.0030 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0005 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

Issued - January 27, 2022

# Hydro One Networks Inc.
## Former Haldimand County Hydro Inc. Service Area
## TARIFF OF RATES AND CHARGES
### Effective Date January 1, 2022
### Implementation Date February 1, 2022
**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2021-0033**

## STREET LIGHTING SERVICE CLASSIFICATION

This classification applies to an account for roadway lighting with a Municipality, Regional Municipality, Ministry of Transportation and private roadway lighting, controlled by photo cells. The consumption for these customers will be based on the calculated connected load times the required lighting times established in the approved Ontario Energy Board street lighting load shape template. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge (per connection) | $ | 5.97 |
| Rate Rider for Recovery of Foregone Revenue - effective until December 31, 2022 | $ | 0.02 |
| Distribution Volumetric Rate | $/kW | 15.2665 |
| Low Voltage Service Rate | $/kW | 0.1130 |
| Funding Adder for Renewable Energy Generation - in effect until the effective date of the next cost of service based rate order | $/kW | 0.2152 |
| Rate Rider for Disposition of Group 2 Accounts (Excluding LRAMVA) - effective until December 31, 2022 | $/kW | (1.4539) |
| Rate Rider for Recovery of Foregone Revenue - effective until December 31, 2022 | $/kW | 0.0385 |
| Retail Transmission Rate - Network Service Rate | $/kW | 1.9150 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kW | 1.7294 |

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR | $/kWh | 0.0030 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0005 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Hydro One Networks Inc.
## Former Haldimand County Hydro Inc. Service Area
## TARIFF OF RATES AND CHARGES
### Effective Date January 1, 2022
### Implementation Date February 1, 2022
**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2021-0033**

## EMBEDDED DISTRIBUTOR SERVICE CLASSIFICATION FOR HYDRO ONE

This classification applies to Hydro One Networks Inc., an electricity distributor licensed by the Ontario Energy Board, and provided electricity by means of Haldimand County Hydro Inc.'s distribution facilities. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 485.75 |
| Distribution Wheeling Service Rate | $/kW | 1.4969 |
| Retail Transmission Rate - Network Service Rate | $/kW | 3.1746 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kW | 3.0139 |

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR | $/kWh | 0.0030 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0005 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Hydro One Networks Inc.

## Former Haldimand County Hydro Inc. Service Area

## TARIFF OF RATES AND CHARGES

### Effective Date January 1, 2022

### Implementation Date February 1, 2022

**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2021-0033**

## microFIT SERVICE CLASSIFICATION

This classification applies to an electricity generation facility contracted under the Independent Electricity System Operator's microFIT program and connected to the distributor's distribution system. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 4.55 |

# Hydro One Networks Inc.
## Former Haldimand County Hydro Inc. Service Area
## TARIFF OF RATES AND CHARGES
### Effective Date January 1, 2022
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**EB-2021-0033**

## ALLOWANCES

| | | |
|---|---|---|
| Transformer Allowance for Ownership - per kW of billing demand/month | $/kW | (0.60) |
| Primary Metering Allowance for Transformer Losses - applied to measured demand & energy | % | (1.00) |

## SPECIFIC SERVICE CHARGES

**APPLICATION**

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

### Customer Administration

| | | |
|---|---|---|
| Legal letter charge | $ | 15.00 |
| Credit reference/credit check (plus credit agency costs) | $ | 15.00 |
| Returned cheque (plus bank charges) | $ | 15.00 |
| Account set up charge/change of occupancy charge (plus credit agency costs if applicable) | $ | 30.00 |
| Meter dispute charge plus Measurement Canada fees (if meter found correct) | $ | 30.00 |

### Non-Payment of Account

| | | |
|---|---|---|
| Late payment - per month (effective annual rate of 19.56% per annum or 0.04896% compounded daily rate) | % | 1.50 |
| Reconnection charge - at meter during regular hours | $ | 65.00 |
| Reconnection charge - at meter after regular hours | $ | 185.00 |
| Reconnection at pole - during regular hours | $ | 185.00 |
| Reconnection at pole - after regular hours | $ | 415.00 |

### Other

| | | |
|---|---|---|
| Temporary service install & remove - overhead - no transformer | $ | 500.00 |
| Specific charge for access to the power poles - $/pole/year (with the exception of wireless attachments) | $ | 34.76 |
| Bell Canada pole rentals | $ | 18.08 |
| Norfolk pole rentals - billed | $ | 28.61 |

Issued - January 27, 2022

# Hydro One Networks Inc.
## Former Haldimand County Hydro Inc. Service Area
## TARIFF OF RATES AND CHARGES
### Effective Date January 1, 2022
### Implementation Date February 1, 2022
**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2021-0033**

## RETAIL SERVICE CHARGES (if applicable)

**APPLICATION**

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

Retail Service Charges refer to services provided by a distributor to retailers or customers related to the supply of competitive electricity.

| | | |
|---|---|---|
| One-time charge, per retailer, to establish the service agreement between the distributor and the retailer | $ | 107.68 |
| Monthly fixed charge, per retailer | $ | 43.08 |
| Monthly variable charge, per customer, per retailer | $/cust. | 1.07 |
| Distributor-consolidated billing monthly charge, per customer, per retailer | $/cust. | 0.64 |
| Retailer-consolidated billing monthly credit, per customer, per retailer | $/cust. | -0.64 |
| Service Transaction Requests (STR) | | |
| Request fee, per request, applied to the requesting party | $ | 0.54 |
| Processing fee, per request, applied to the requesting party | $ | 1.07 |
| Request for customer information as outlined in Section 10.6.3 and Chapter 11 of the Retail Settlement Code directly to retailers and customers, if not delivered electronically through the Electronic Business Transaction (EBT) system, applied to the requesting party | | |
| Up to twice a year | | no charge |
| More than twice a year, per request (plus incremental delivery costs) | $ | 4.31 |
| Notice of switch letter charge, per letter (unless the distributor has opted out of applying the charge as per the Ontario Energy Board's Decision and Order EB-2015-0304, issued on February 14, 2019) | $ | 2.15 |

## LOSS FACTORS

If the distributor is not capable of prorating changed loss factors jointly with distribution rates, the revised loss factors will be implemented upon the first subsequent billing for each billing cycle.

| | |
|---|---|
| Total Loss Factor - Secondary Metered Customer < 5,000 kW | 1.0655 |
| Total Loss Factor - Primary Metered Customer < 5,000 kW | 1.0548 |
| Total Loss Factor - Embedded Distributor - Hydro One Networks Inc. | 1.0288 |

# Hydro One Networks Inc.
## Former Woodstock Hydro Services Inc. Service Area
## TARIFF OF RATES AND CHARGES
### Effective Date January 1, 2022
### Implementation Date February 1, 2022
**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2021-0033**

## RESIDENTIAL SERVICE CLASSIFICATION

This classification applies to an account taking electricity at 750 volts or less where the electricity is used exclusively in a separate metered living accommodation. Customers shall be residing in single-dwelling units that consist of a detached house or one unit of a semi-detached, duplex, triplex or quadruplex house, with a residential zoning. Separately metered dwellings within a town house complex or apartment building also qualify as residential customers. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 31.42 |
| Rate Rider for Recovery of Foregone Revenue - effective until December 31, 2022 | $ | 0.08 |
| Rate Rider for Disposition of Group 2 Accounts (Excluding 1576 and LRAMVA) - effective until December 31, 2022 | $ | 0.62 |
| Rate Rider for Disposition of Account 1576 - effective until December 31, 2022 | $ | (8.64) |
| Smart Metering Entity Charge - effective until December 31, 2022 | $ | 0.57 |
| Rate Rider for Recovery of Smart Meter Incremental Revenue Requirement - in effect until the effective date of the next cost of service based rate order | $ | 0.64 |
| Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2022) - effective until December 31, 2023 | $/kWh | 0.0003 |
| Retail Transmission Rate - Network Service Rate | $/kWh | 0.0077 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kWh | 0.0064 |

# Hydro One Networks Inc.

## Former Woodstock Hydro Services Inc. Service Area

## TARIFF OF RATES AND CHARGES

### Effective Date January 1, 2022

### Implementation Date February 1, 2022

**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2021-0033**

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR | $/kWh | 0.0030 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0005 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Hydro One Networks Inc.
## Former Woodstock Hydro Services Inc. Service Area
## TARIFF OF RATES AND CHARGES
### Effective Date January 1, 2022
### Implementation Date February 1, 2022
**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2021-0033**

## GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION

This classification applies to a non residential account taking electricity at 750 volts or less whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 26.36 |
| Rate Rider for Recovery of Foregone Revenue - effective until December 31, 2022 | $ | 0.07 |
| Smart Metering Entity Charge - effective until December 31, 2022 | $ | 0.57 |
| Rate Rider for Recovery of Smart Meter Incremental Revenue Requirement - in effect until the effective date of the next cost of service based rate order | $ | 4.24 |
| Distribution Volumetric Rate | $/kWh | 0.0152 |
| Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2022) - effective until December 31, 2023 | $/kWh | 0.0037 |
| Rate Rider for Disposition of Account 1576 - effective until December 31, 2022 | $/kWh | (0.0068) |
| Rate Rider for Disposition of Group 2 Accounts (Excluding 1576 and LRAMVA) - effective until December 31, 2022 | $/kWh | 0.0005 |
| Retail Transmission Rate - Network Service Rate | $/kWh | 0.0070 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kWh | 0.0060 |

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR | $/kWh | 0.0030 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0005 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Hydro One Networks Inc.
## Former Woodstock Hydro Services Inc. Service Area
## TARIFF OF RATES AND CHARGES
### Effective Date January 1, 2022
### Implementation Date February 1, 2022
**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2021-0033**

## GENERAL SERVICE 50 TO 999 KW SERVICE CLASSIFICATION

This classification applies to a non residential account whose average monthly maximum demand used for billing purposes is equal to or greater than, or is forecast to be equal to or greater than, 50 kW but less than 1,000 kW. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

If included in the following listing of monthly rates and charges, the rate rider for the disposition of WMS - Sub-account CBR Class B is not applicable to wholesale market participants (WMP), customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new Class B customers.

If included in the following listing of monthly rates and charges, the rate rider for the disposition of Global Adjustment is only applicable to non-RPP Class B customers. It is not applicable to WMP, customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new non-RPP Class B customers.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

# Hydro One Networks Inc.
## Former Woodstock Hydro Services Inc. Service Area
## TARIFF OF RATES AND CHARGES
### Effective Date January 1, 2022
### Implementation Date February 1, 2022
**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2021-0033**

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 146.47 |
| Rate Rider for Recovery of Foregone Revenue - effective until December 31, 2022 | $ | 0.37 |
| Distribution Volumetric Rate | $/kW | 2.6975 |
| Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2022) - effective until December 31, 2023 | $/kW | 0.6839 |
| Rate Rider for Disposition of Account 1576 - effective until December 31, 2022 | $/kW | (1.0156) |
| Rate Rider for Disposition of Group 2 Accounts (Excluding 1576 and LRAMVA) - effective until December 31, 2022 | $/kW | 0.0724 |
| Rate Rider for Recovery of Foregone Revenue - effective until December 31, 2022 | $/kW | 0.0068 |
| Retail Transmission Rate - Network Service Rate | $/kW | 2.9915 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kW | 2.5605 |

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR | $/kWh | 0.0030 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0005 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Hydro One Networks Inc.
## Former Woodstock Hydro Services Inc. Service Area
## TARIFF OF RATES AND CHARGES
### Effective Date January 1, 2022
### Implementation Date February 1, 2022
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**approved schedules of Rates, Charges and Loss Factors**

**EB-2021-0033**

## GENERAL SERVICE GREATER THAN 1,000 KW SERVICE CLASSIFICATION

This classification applies to a non-residential account whose average monthly maximum demand used for billing purposes is equal to or greater than, or is forecast to be equal to or greater than, 1,000 kW. Class A and Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

If included in the following listing of monthly rates and charges, the rate rider for the disposition of WMS - Sub-account CBR Class B is not applicable to wholesale market participants (WMP), customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new Class B customers.

If included in the following listing of monthly rates and charges, the rate rider for the disposition of Global Adjustment is only applicable to non-RPP Class B customers. It is not applicable to WMP, customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new non-RPP Class B customers.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

# Hydro One Networks Inc.
## Former Woodstock Hydro Services Inc. Service Area
## TARIFF OF RATES AND CHARGES
### Effective Date January 1, 2022
### Implementation Date February 1, 2022
**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2021-0033**

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 542.98 |
| Rate Rider for Recovery of Foregone Revenue - effective until December 31, 2022 | $ | 1.37 |
| Distribution Volumetric Rate | $/kW | 2.8671 |
| Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2022) - effective until December 31, 2023 | $/kW | 0.5521 |
| Rate Rider for Disposition of Account 1576 - effective until December 31, 2022 | $/kW | (0.8709) |
| Rate Rider for Disposition of Group 2 Accounts (Excluding 1576 and LRAMVA) - effective until December 31, 2022 | $/kW | 0.0621 |
| Rate Rider for Recovery of Foregone Revenue - effective until December 31, 2022 | $/kW | 0.0072 |
| Retail Transmission Rate - Network Service Rate | $/kW | 2.9915 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kW | 2.5605 |

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR | $/kWh | 0.0030 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0005 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Hydro One Networks Inc.
## Former Woodstock Hydro Services Inc. Service Area
## TARIFF OF RATES AND CHARGES
### Effective Date January 1, 2022
### Implementation Date February 1, 2022
**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2021-0033**

## UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

This classification applies to an account taking electricity at 750 volts or less whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW and the consumption is unmetered. Such connections include cable TV power packs, bus shelters, telephone booths, traffic lights, railway crossings, etc. The level of the consumption will be agreed to by the distributor and the customer, based on detailed manufacturer information/ documentation with regard to electrical consumption of the unmetered load or periodic monitoring of actual consumption. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 11.02 |
| Rate Rider for Recovery of Foregone Revenue - effective until December 31, 2022 | $ | 0.03 |
| Distribution Volumetric Rate | $/kWh | 0.0128 |
| Rate Rider for Disposition of Account 1576 - effective until December 31, 2022 | $/kWh | (0.0058) |
| Rate Rider for Disposition of Group 2 Accounts (Excluding 1576 and LRAMVA) - effective until December 31, 2022 | $/kWh | 0.0004 |
| Retail Transmission Rate - Network Service Rate | $/kWh | 0.0070 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kWh | 0.0060 |

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR | $/kWh | 0.0030 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0005 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Hydro One Networks Inc.
## Former Woodstock Hydro Services Inc. Service Area
## TARIFF OF RATES AND CHARGES
### Effective Date January 1, 2022
### Implementation Date February 1, 2022
**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2021-0033**

## STREET LIGHTING SERVICE CLASSIFICATION

This classification applies to an account for roadway lighting with a Municipality, Regional Municipality, Ministry of Transportation and private roadway lighting, controlled by photo cells. The consumption for these customers will be based on the calculated connected load times the required lighting times established in the approved Ontario Energy Board street lighting load shape template. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 3.23 |
| Rate Rider for Recovery of Foregone Revenue - effective until December 31, 2022 | $ | 0.01 |
| Distribution Volumetric Rate | $/kW | 13.0344 |
| Rate Rider for Disposition of Account 1576 - effective until December 31, 2022 | $/kW | (10.3543) |
| Rate Rider for Disposition of Group 2 Accounts (Excluding 1576 and LRAMVA) - effective until December 31, 2022 | $/kW | 0.7382 |
| Rate Rider for Recovery of Foregone Revenue - effective until December 31, 2022 | $/kW | 0.0332 |
| Retail Transmission Rate - Network Service Rate | $/kW | 2.2078 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kW | 1.8899 |

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR | $/kWh | 0.0030 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0005 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

Issued - January 27, 2022

# Hydro One Networks Inc.
## Former Woodstock Hydro Services Inc. Service Area
## TARIFF OF RATES AND CHARGES
### Effective Date January 1, 2022
### Implementation Date February 1, 2022
**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2021-0033**

## microFIT SERVICE CLASSIFICATION

This classification applies to an electricity generation facility contracted under the Independent Electricity System Operator's microFIT program and connected to the distributor's distribution system. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 4.55 |

# Hydro One Networks Inc.
## Former Woodstock Hydro Services Inc. Service Area
## TARIFF OF RATES AND CHARGES
### Effective Date January 1, 2022
### Implementation Date February 1, 2022
**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2021-0033**

## ALLOWANCES

| | | |
|---|---|---|
| Transformer Allowance for Ownership - per kW of billing demand/month | $/kW | (0.60) |
| Primary Metering Allowance for Transformer Losses - applied to measured demand & energy | % | (1.00) |

## SPECIFIC SERVICE CHARGES

**APPLICATION**

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor’s Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

**Customer Administration**

| | | |
|---|---|---|
| Notification charge | $ | 15.00 |
| Returned cheque (plus bank charges) | $ | 15.00 |
| Legal letter charge | $ | 15.00 |
| Account set up charge / change of occupancy charge (plus credit agency costs if applicable) | $ | 30.00 |
| Meter dispute charge plus Measurement Canada fees (if meter found correct) | $ | 30.00 |
| Statement of account | $ | 15.00 |
| Account history | $ | 15.00 |

**Non-Payment of Account**

| | | |
|---|---|---|
| Late payment - per month (effective annual rate 19.56% per annum or 0.04896% compounded daily rate) | % | 1.50 |
| Reconnection at meter - during regular hours | $ | 65.00 |
| Reconnection at meter - after regular hours | $ | 185.00 |

**Other**

| | | |
|---|---|---|
| Special meter reads | $ | 30.00 |
| Specific charge for access to the power poles - $/pole/year (with the exception of wireless attachments) | $ | 34.76 |

# Hydro One Networks Inc.
## Former Woodstock Hydro Services Inc. Service Area
## TARIFF OF RATES AND CHARGES
### Effective Date January 1, 2022
### Implementation Date February 1, 2022
**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2021-0033**

## RETAIL SERVICE CHARGES (if applicable)

**APPLICATION**

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

Retail Service Charges refer to services provided by a distributor to retailers or customers related to the supply of competitive electricity.

| | | |
|---|---|---|
| One-time charge, per retailer, to establish the service agreement between the distributor and the retailer | $ | 107.68 |
| Monthly fixed charge, per retailer | $ | 43.08 |
| Monthly variable charge, per customer, per retailer | $/cust. | 1.07 |
| Distributor-consolidated billing monthly charge, per customer, per retailer | $/cust. | 0.64 |
| Retailer-consolidated billing monthly credit, per customer, per retailer | $/cust. | -0.64 |
| Service Transaction Requests (STR) | | |
| Request fee, per request, applied to the requesting party | $ | 0.54 |
| Processing fee, per request, applied to the requesting party | $ | 1.07 |
| Request for customer information as outlined in Section 10.6.3 and Chapter 11 of the Retail Settlement Code directly to retailers and customers, if not delivered electronically through the Electronic Business Transaction (EBT) system, applied to the requesting party | | |
| Up to twice a year | | no charge |
| More than twice a year, per request (plus incremental delivery costs) | $ | 4.31 |
| Notice of switch letter charge, per letter (unless the distributor has opted out of applying the charge as per the Ontario Energy Board's Decision and Order EB-2015-0304, issued on February 14, 2019) | $ | 2.15 |

## LOSS FACTORS

If the distributor is not capable of prorating changed loss factors jointly with distribution rates, the revised loss factors will be implemented upon the first subsequent billing for each billing cycle.

| | |
|---|---|
| Total Loss Factor - Secondary Metered Customer < 5,000 kW | 1.0431 |
| Total Loss Factor - Secondary Metered Customer > 5,000 kW | 1.0145 |
| Total Loss Factor - Primary Metered Customer < 5,000 kW | 1.0326 |
| Total Loss Factor - Primary Metered Customer > 5,000 kW | 1.0044 |

# Hydro One Networks Inc.

## TARIFF OF RATES AND CHARGES

### Effective and Implementation Date January 1, 2023

**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2021-0110**

## RESIDENTIAL SERVICE CLASSIFICATIONS - HYDRO ONE NETWORKS INC. SERVICE AREA

These classifications apply to year-round and seasonal residential properties. A year-round residential property, located in Hydro One Networks Inc.'s service area excluding former Norfolk Power Distribution Inc., Haldimand County Hydro Inc. and Woodstock Hydro Services Inc.'s service areas., is considered to be customer's main place of abode and may include additional buildings served through the same meter, provided they are not rental income units. All of the following criteria must be met:

1. Occupant represents and warrants to Hydro One Networks Inc. that for so long as he/she has year-round residential rate status for the identified dwelling, he/she will not designate another property that he/she owns as a year-round residence for purposes of Hydro One rate classification.
2. Occupier must live in this residence for at least four (4) days of the week for eight (8) months of the year and the Occupier must not reside anywhere else for more than three (3) days a week during eight (8) months of the year.
3. The address of this residence must appear on documents such as the occupant's electric bill, driver's licence, credit card invoice, property tax bill, etc.
4. Occupants who are eligible to vote in Provincial of Federal elections must be enumerated for this purpose at the address of this residence.

A seasonal property is defined as any residential service that does not meet residential year-round criteria. It includes dwellings such as cottages, chalets and camps.

Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's conditions of Service.

### APPLICATION

Hydro One Networks' residential service area is sub-divided into three density zones according to the following:

- Urban Density Zone is defined as areas containing 3,000 or more customers with a line density of at least 60 customers per circuit kilometer.
- Medium Density Zone is defined as areas containing 100 or more customers with a line density of at least 15 customers per circuit kilometer.
- Low Density Zone is defined as areas other than Urban or Medium Density Zone.

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor’s Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

# Hydro One Networks Inc.
## TARIFF OF RATES AND CHARGES
### Effective and Implementation Date January 1, 2023
**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2021-0110**

## URBAN DENSITY - UR
### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 36.54 |
| Base Rate Adjustment to Recover Past Tax Amounts (applicable to year-round high-density customers) - effective until June 30, 2023 | $ | 0.83 |
| Base Rate Adjustment to Recover Past Tax Amounts (applicable to Seasonal customers) - effective until June 30, 2023 | $ | 1.79 |
| Smart Metering Entity Charge - effective until December 31, 2027 | $ | 0.42 |
| Rate Rider for Disposition of Group 2 Deferral/Variance Accounts (2023) - effective until December 31, 2025 | $ | (0.11) |
| Rate Rider for Disposition of Group 1 Deferral/Variance Accounts (2023) - effective until December 31, 2025 | $/kWh | (0.0007) |
| Rate Rider for Disposition of Global Adjustment Account (2023) - effective until December 31, 2025 (see Note 13) | $/kWh | (0.0009) |
| Retail Transmission Rate - Network Service Rate (see Note 4) | $/kWh | 0.0119 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate (see Note 5) | $/kWh | 0.0082 |

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR (see Note 12) | $/kWh | 0.0030 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers (see Note 12) | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) (see Note 12) | $/kWh | 0.0005 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Hydro One Networks Inc.
## TARIFF OF RATES AND CHARGES
### Effective and Implementation Date January 1, 2023
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**EB-2021-0110**

## MEDIUM DENSITY - R1**
### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 58.22 |
| Base Rate Adjustment to Recover Past Tax Amounts (applicable to year-round medium-density customers) - effective until June 30, 2023 | $ | 1.56 |
| Base Rate Adjustment to Recover Past Tax Amounts (applicable to Seasonal customers) - effective until June 30, 2023 | $ | 1.79 |
| Smart Metering Entity Charge - effective until December 31, 2027 | $ | 0.42 |
| Rate Rider for Disposition of Group 2 Deferral/Variance Accounts (2023) - effective until December 31, 2025 | $ | (0.21) |
| Distribution Volumetric Rate | $/kWh | 0.0053 |
| Rate Rider for Disposition of Group 1 Deferral/Variance Accounts (2023) - effective until December 31, 2025 | $/kWh | (0.0007) |
| Rate Rider for Disposition of Global Adjustment Account (2023) - effective until December 31, 2025 (see Note 13) | $/kWh | (0.0009) |
| Retail Transmission Rate - Network Service Rate (see Note 4) | $/kWh | 0.0110 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate (see Note 5) | $/kWh | 0.0077 |

**The rates set out above do not reflect the impact of the Distribution Rate Protection program on R1 customers per Ontario Regulation 198/17.

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR (see Note 12) | $/kWh | 0.0030 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers (see Note 12) | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) (see Note 12) | $/kWh | 0.0005 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Hydro One Networks Inc.
## TARIFF OF RATES AND CHARGES
### Effective and Implementation Date January 1, 2023
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**EB-2021-0110**

## LOW DENSITY - R2**
### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge* - applicable to year-round low-density customers | $ | 118.64 |
| Service Charge - applicable to Seasonal customers | $ | 65.25 |
| Base Rate Adjustment to Recover Past Tax Amounts (applicable to year-round low-density customers) - effective until June 30, 2023 | $ | 4.42 |
| Base Rate Adjustment to Recover Past Tax Amounts (applicable to Seasonal customers) - effective until June 30, 2023 | $ | 1.79 |
| Smart Metering Entity Charge - effective until December 31, 2027 | $ | 0.42 |
| Rate Rider for Disposition of Group 2 Deferral/Variance Accounts (2023) - effective until December 31, 2025 | $ | (0.44) |
| Distribution Volumetric Rate | $/kWh | 0.0187 |
| Rate Rider for Disposition of Group 1 Deferral/Variance Accounts (2023) - effective until December 31, 2025 | $/kWh | (0.0007) |
| Rate Rider for Disposition of Global Adjustment Account (2023) - effective until December 31, 2025 (see Note 13) | $/kWh | (0.0009) |
| Retail Transmission Rate - Network Service Rate (see Note 4) | $/kWh | 0.0102 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate (see Note 5) | $/kWh | 0.0072 |

*Under the Ontario Energy Board Act, 1998 and associated Regulations, every qualifying year-round customer with a principal residence is eligible to receive Rural of Remote Rate Protection (RRRP). The service charge shown for eligible R2 customers will be reduced by the applicable RRRP credit, currently at $60.50.

**The rates set out above do not reflect the impact of the Distribution Rate Protection program on R2 customers per Ontario Regulation 198/17.

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR (see Note 12) | $/kWh | 0.0030 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers (see Note 12) | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) (see Note 12) | $/kWh | 0.0005 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Hydro One Networks Inc.
## TARIFF OF RATES AND CHARGES
### Effective and Implementation Date January 1, 2023
**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2021-0110**

## GENERAL SERVICE CLASSIFICATIONS - HYDRO ONE NETWORKS INC. SERVICE AREA

These classifications apply to properties located in Hydro One Networks Inc.'s service area, which excludes former Norfolk Power Distribution Inc., Haldimand County Hydro Inc. and Woodstock Hydro Services Inc.'s service areas with one exception - Sub-Transmission (ST). The ST rate class applies to properties located in Hydro One Networks Inc. service area as well as former Norfolk Power Distribution Inc., Haldimand County Hydro Inc. and Woodstock Hydro Service Inc.'s service areas. General Service classification applies to any service that does not fit the description of residential classes. It includes combination type services where a variety of uses are made of the service by the owner of one property, and all multiple services except residential. Class A and Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

Hydro One Networks' General Service area is sub-divided into two density zones according to the following:

- Urban Density Zone is defined as areas containing 3,000 or more customers with a line density of at least 60 customers per circuit kilometer.
- Non-Urban Density Zone is defined as areas other than Urban Density Zone.

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

If included in the following listing of monthly rates and charges, the rate rider for the disposition of WMS - Sub-account CBR Class B is not applicable to wholesale market participants (WMP), customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new Class B customers.

If included in the following listing of monthly rates and charges, the rate rider for the disposition of Global Adjustment is only applicable to non-RPP Class B customers. It is not applicable to WMP, customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new non-RPP Class B customers.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

# Hydro One Networks Inc.
## TARIFF OF RATES AND CHARGES
### Effective and Implementation Date January 1, 2023
**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2021-0110**

## URBAN GENERAL SERVICE ENERGY BILLED - UGe

This classification applies to a non-residential account located in an Urban Density Zone whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW.

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 24.39 |
| Base Rate Adjustment to Recover Past Tax Amounts - effective until June 30, 2023 | $ | 0.81 |
| Smart Metering Entity Charge - effective until December 31, 2027 | $ | 0.42 |
| Distribution Volumetric Rate | $/kWh | 0.0317 |
| Base Rate Adjustment to Recover Past Tax Amounts - effective until June 30, 2023 | $/kWh | 0.0010 |
| Rate Rider for Disposition of Group 1 Deferral/Variance Accounts (2023) - effective until December 31, 2025 | $/kWh | (0.0007) |
| Rate Rider for Disposition of Group 2 Deferral/Variance Accounts (2023) - effective until December 31, 2025 | $/kWh | (0.0001) |
| Rate Rider for Disposition of Global Adjustment Account (2023) - effective until December 31, 2025 (see Note 13) | $/kWh | (0.0009) |
| Retail Transmission Rate - Network Service Rate (see Note 4) | $/kWh | 0.0093 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate (see Note 5) | $/kWh | 0.0069 |

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR (see Note 12) | $/kWh | 0.0030 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers (see Note 12) | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) (see Note 12) | $/kWh | 0.0005 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Hydro One Networks Inc.
## TARIFF OF RATES AND CHARGES
### Effective and Implementation Date January 1, 2023
**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2021-0110**

## GENERAL SERVICE ENERGY BILLED - GSe

This classification applies to a non-residential account not located in an Urban Density Zone whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW.

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 31.33 |
| Base Rate Adjustment to Recover Past Tax Amounts - effective until June 30, 2023 | $ | 1.11 |
| Smart Metering Entity Charge - effective until December 31, 2027 | $ | 0.42 |
| Distribution Volumetric Rate | $/kWh | 0.0661 |
| Base Rate Adjustment to Recover Past Tax Amounts - effective until June 30, 2023 | $/kWh | 0.0022 |
| Rate Rider for Disposition of Group 1 Deferral/Variance Accounts (2023) - effective until December 31, 2025 | $/kWh | (0.0007) |
| Rate Rider for Disposition of Group 2 Deferral/Variance Accounts (2023) - effective until December 31, 2025 | $/kWh | (0.0003) |
| Rate Rider for Disposition of Global Adjustment Account (2023) - effective until December 31, 2025 (see Note 13) | $/kWh | (0.0009) |
| Retail Transmission Rate - Network Service Rate (see Note 4) | $/kWh | 0.0087 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate (see Note 5) | $/kWh | 0.0065 |

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR (see Note 12) | $/kWh | 0.0030 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers (see Note 12) | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) (see Note 12) | $/kWh | 0.0005 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Hydro One Networks Inc.
## TARIFF OF RATES AND CHARGES
### Effective and Implementation Date January 1, 2023
**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2021-0110**

## URBAN GENERAL SERVICE DEMAND BILLED - UGd

This classification applies to a non-residential account located in an Urban Density Zone whose average monthly maximum demand is equal to or greater than, or is forecast to be equal to or greater than, 50 kW. Hydro One establishes billing determinants for demand customers' Distribution charges at the greater of 100 per cent of kW and 90 per cent of kVA where kVA metering is installed. When a customer's power factor is known to be less than 90 per cent, a kVA meter of equivalent electronic meter shall be used for measuring and billing.

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 92.16 |
| Base Rate Adjustment to Recover Past Tax Amounts - effective until June 30, 2023 | $ | 3.9200 |
| Distribution Volumetric Rate | $/kW | 10.8745 |
| Base Rate Adjustment to Recover Past Tax Amounts - effective until June 30, 2023 | $/kW | 0.4134 |
| Rate Rider for Disposition of Group 1 Deferral/Variance Accounts (General) (2023) - effective until December 31, 2025 (see Note 9) | $/kW | (0.1057) |
| Rate Rider for Disposition of Group 1 Deferral/Variance Accounts (Non-WMP) (2023) - effective until December 31, 2025 (see Note 10) | $/kW | (0.1479) |
| Rate Rider for Disposition of Group 2 Deferral/Variance Accounts (2023) - effective until December 31, 2025 | $/kW | (0.0421) |
| Rate Rider for Disposition of Global Adjustment Account (2023) - effective until December 31, 2025 (see Note 13) | $/kWh | (0.0009) |
| Retail Transmission Rate - Network Service Rate (see Note 4) | $/kW | 3.4468 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate (see Note 5) | $/kW | 2.4821 |

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR (see Note 12) | $/kWh | 0.0030 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers (see Note 12) | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) (see Note 12) | $/kWh | 0.0005 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Hydro One Networks Inc.
## TARIFF OF RATES AND CHARGES
### Effective and Implementation Date January 1, 2023
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**EB-2021-0110**

## GENERAL SERVICE DEMAND BILLED - GSd

This classification applies to a non-residential account not located in an Urban Density Zone whose average monthly maximum demand is equal to or greater than, or is forecast to be equal to or greater than, 50 kW. Hydro One establishes billing determinants for demand customers' Distribution charges at the greater of 100 per cent of kW and 90 per cent of kVA where kVA metering is installed. When a customer's power factor is known to be less than 90 per cent, a kVA meter or other equivalent electronic meter shall be used for measuring and billing.

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 100.82 |
| Base Rate Adjustment to Recover Past Tax Amounts - effective until June 30, 2023 | $ | 4.34 |
| Distribution Volumetric Rate | $/kW | 18.7295 |
| Base Rate Adjustment to Recover Past Tax Amounts - effective until June 30, 2023 | $/kW | 0.7338 |
| Rate Rider for Disposition of Group 1 Deferral/Variance Accounts (General) (2023) - effective until December 31, 2025 (see Note 9) | $/kW | (0.0858) |
| Rate Rider for Disposition of Group 1 Deferral/Variance Accounts (Non-WMP) (2023) - effective until December 31, 2025 (see Note 10) | $/kW | (0.1200) |
| Rate Rider for Disposition of Group 2 Deferral/Variance Accounts (2023) - effective until December 31, 2025 | $/kW | (0.0711) |
| Rate Rider for Disposition of Global Adjustment Account (2023) - effective until December 31, 2025 (see Note 13) | $/kWh | (0.0009) |
| Retail Transmission Rate - Network Service Rate (see Note 4) | $/kW | 2.6686 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate (see Note 5) | $/kW | 1.9553 |

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR (see Note 12) | $/kWh | 0.0030 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers (see Note 12) | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) (see Note 12) | $/kWh | 0.0005 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Hydro One Networks Inc.
## TARIFF OF RATES AND CHARGES
### Effective and Implementation Date January 1, 2023
**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2021-0110**

## DISTRIBUTED GENERATION - DGen

This classification applies to an embedded retail generation facility connected to the distribution system that is not classified as MicroFIT generation. Hydro One establishes billing determinants for demand customers' Distribution charges at the greater of 100 per cent of kW and 90 per cent of kVA where kVA metering is installed. When a customer's power factor is known to be less than 90 per cent, a kVA meter or other equivalent electronic meter shall be used for measuring and billing. Class A and Class B consumers are defined in accordance with O. Reg. 429/04.

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 190.79 |
| Base Rate Adjustment to Recover Past Tax Amounts - effective until June 30, 2023 | $ | 1.74 |
| Distribution Volumetric Rate | $/kW | 11.0564 |
| Base Rate Adjustment to Recover Past Tax Amounts - effective until June 30, 2023 | $/kW | 0.0883 |
| Rate Rider for Disposition of Group 1 Deferral/Variance Accounts (General) (2023) - effective until December 31, 2025 (see Note 9) | $/kW | (0.0396) |
| Rate Rider for Disposition of Group 1 Deferral/Variance Accounts (Non-WMP) (2023) - effective until December 31, 2025 (see Note 10) | $/kW | (0.0567) |
| Rate Rider for Disposition of Group 2 Deferral/Variance Accounts (2023) - effective until December 31, 2025 | $/kW | (0.0934) |
| Rate Rider for Disposition of Global Adjustment Account (2023) - effective until December 31, 2025 (see Note 13) | $/kWh | (0.0009) |
| Retail Transmission Rate - Network Service Rate (see Note 4) | $/kW | 1.4646 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate (see Note 5) | $/kW | 0.8390 |

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR (see Note 12) | $/kWh | 0.0030 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers (see Note 12) | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) (see Note 12) | $/kWh | 0.0005 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Hydro One Networks Inc.
## TARIFF OF RATES AND CHARGES
### Effective and Implementation Date January 1, 2023
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**EB-2021-0110**

## SUB TRANSMISSION - ST

This classification applies to either:

- Embedded supply to Local Distribution Companies (LDCs). "Embedded" meaning receiving supply via Hydro One Distribution assets, and where Hydro One is the host distributor to the embedded LDC. Situations where the LDC is supplied via Specific Facilities are included. OR
- Load which:
  - is three-phase; and
  - is connected to and supplied from Hydro One Distribution assets between 44 kV and 13.8 kV inclusive, where 44 kV and 13.8 kV are the voltage of the primary side of the local transformer; local transformer can be Hydro One-owned or customer-owned; and
  - is greater than 500 kW (monthly measured maximum demand averaged over the most recent calendar year or whose forecasted monthly average demand over twelve consecutive months is greater than 500 kW).

Hydro One establishes billing determinants for demand customers' Distribution charges at the greater of 100 per cent of kW and 90 per cent of kVA where kVA metering is installed. When a customer's power factor is known to be less than 90 per cent, a kVA meter or other equivalent electronic meter shall be used for measuring and billing.

Class A and Class B consumers are defined in accordance with O. Reg. 429/04.

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 790.43 |
| Meter Charge (for Hydro One ownership) (see Note 11) | $ | 396.96 |
| Local Transformation Charge (per transformer) (see Note 15) | $ | 200.00 |
| Base Rate Adjustment to Recover Past Tax Amounts (Applicable to Hydro One legacy customers only) (see Note 16) - effective until June 30, 2023 | $ | 36.18 |
| Facility Charge for connection to Common ST Lines (44 kV to 13.8 kV) (see Notes 1, 8 and 14) | $/kW | 1.4769 |
| Base Rate Adjustment to Recover Past Tax Amounts (Applicable to Hydro One legacy customers only) (see Notes 1 and 16) - effective until June 30, 2023 | $/kW | 0.0540 |
| Facility Charge for connection to Specific ST Lines (44 kV to 13.8 kV) (see Note 2) | $/km | 595.4935 |
| Facility Charge for connection to high-voltage (> 13.8 kV secondary) delivery High Voltage Distribution Station (see Notes 1 and 14) | $/kW | 2.9907 |
| Facility Charge for connection to low-voltage (< 13.8 kV secondary) delivery High Voltage Distribution Station (see Notes 1 and 14) | $/kW | 4.8501 |
| Facility Charge for connection to low-voltage (< 13.8 kV secondary) Low Voltage Distribution Station (see Notes 3 and 14) | $/kW | 1.8594 |
| Rate Rider for Disposition of Group 1 Deferral/Variance Accounts (General) (2023) - effective until December 31, 2025 (see Notes 1 and 9) | $/kW | (0.1345) |
| Rate Rider for Disposition of Group 1 Deferral/Variance Accounts (Non-WMP) (2023) - effective until December 31, 2025 (see Notes 1 and 10) | $/kW | (0.1890) |
| Rate Rider for Disposition of Group 2 Deferral/Variance Accounts (2023) (Applicable to Hydro One legacy customers only) (see Notes 1 and 16) - effective until December 31, 2025 | $/kW | (0.0073) |
| Rate Rider for Disposition of Global Adjustment Account (2023) - effective until December 31, 2025 (see Note 13) | $/kWh | (0.0009) |

| | | |
|---|---|---|
| Rate Rider for Disposition of Account 1595 (former Woodstock GS 50-999kW Customers only) (see Note 1) - effective until December 31, 2025 | $/kW | 0.0327 |
| Rate Rider for Disposition of Account 1595 (former Woodstock GS >1,000kW Customers only) (see Note 1) - effective until December 31, 2025 | $/kW | 0.0277 |
| Rate Rider for Disposition of Account 1595 (former Norfolk GS 50-4,999kW Customers only) (see Note 1) - effective until December 31, 2025 | $/kW | 0.0327 |
| Rate Rider for Disposition of Account 1592 (former Norfolk GS 50-4,999kW Customers only) (see Note 1) - effective until December 31, 2025 | $/kW | (0.0618) |
| Rate Rider for Disposition of Account 1592 (former Haldimand GS 50-4,999kW Customers only) (see Note 1) - effective until December 31, 2025 | $/kW | (0.0603) |
| Rate Rider for Disposition of Account 1592 (former Woodstock GS 50-999kW Customers only) (see Note 1) - effective until December 31, 2025 | $/kW | (0.0392) |
| Rate Rider for Disposition of Account 1592 (former Woodstock GS >1,000kW Customers only) (see Note 1) - effective until December 31, 2025 | $/kW | (0.0438) |
| Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (former Woodstock 50-999kW Customer only) (2022) (see Note 1) - effective until December 31, 2023 | $/kW | 0.6839 |
| Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (former Woodstock >1,000kW Customers only) (2022) (see Note 1) - effective until December 31, 2023 | $/kW | 0.5521 |
| Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (former Norfolk 50-4,999kW Customer only) (2022) (see Note 1) - effective until December 31, 2023 | $/kW | 0.2853 |
| Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (former Haldimand 50-4,999kW Customer only) (2022) (see Note 1) - effective until December 31, 2023 | $/kW | (0.0575) |
| Retail Transmission Service Rates (see Notes 6 and 7) | | |
| Retail Transmission Rate - Network Service Rate (see Note 4) | $/kW | 4.6545 |
| Retail Transmission Rate - Line Connection Service Rate (see Note 5) | $/kW | 0.6056 |
| Retail Transmission Rate - Transformation Connection Service Rate (see Note 5) | $/kW | 2.8924 |

## MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR (see Note 12) | $/kWh | 0.0030 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers (see Note 12) | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) (see Note 12) | $/kWh | 0.0005 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Hydro One Networks Inc.
## TARIFF OF RATES AND CHARGES
### Effective and Implementation Date January 1, 2023
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**EB-2021-0110**

## UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

This classification applies to properties located in Hydro One Networks Inc. service area as well as former Norfolk Power Distribution Inc., Haldimand County Hydro Inc. and Woodstock Hydro Services Inc.'s service areas.
Unmetered Scattered Load classification applies to an account taking electricity at 750 volts or less whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW and the consumption is unmetered. The amount of electricity consumed by unmetered connections will be based on detailed information/documentation provided by the device's manufacturer and will be agreed to by Hydro One and the customer and may be subject to periodic monitoring of actual consumption. Eligible unmetered loads include cable TV amplifiers, bus shelters, telephone booths, railway crossings and other small fixed loads. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor’s Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

# Hydro One Networks Inc.
## TARIFF OF RATES AND CHARGES
### Effective and Implementation Date January 1, 2023
**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2021-0110**

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 36.72 |
| Base Rate Adjustment to Recover Past Tax Amounts (Applicable to Hydro One legacy customers only) (see Note 16) - effective until June 30, 2023 | $ | 0.89 |
| Distribution Volumetric Rate | $/kWh | 0.0231 |
| Base Rate Adjustment to Recover Past Tax Amounts (Applicable to Hydro One legacy customers only) (see Note 16) - effective until June 30, 2023 | $/kWh | 0.0006 |
| Rate Rider for Disposition of Group 1 Deferral/Variance Accounts (2023) - effective until December 31, 2025 | $/kWh | (0.0007) |
| Rate Rider for Disposition of Group 2 Deferral/Variance Accounts (2023) (Applicable to Hydro One legacy customers only) (see Note 16) - effective until December 31, 2025 | $/kWh | (0.0003) |
| Rate Rider for Disposition of Global Adjustment Account (2023) - effective until December 31, 2025 (see Note 13) | $/kWh | (0.0009) |
| Rate Rider for Disposition of Account 1595 (Applicable to former Woodstock USL customers only) - effective until December 31, 2025 | $/kWh | (0.0002) |
| Rate Rider for Disposition of Account 1595 (Applicable to former Norfolk USL customers only) - effective until December 31, 2025 | $/kWh | (0.0007) |
| Rate Rider for Disposition of Account 1592 (Applicable to former Norfolk USL customers only) - effective until December 31, 2025 | $/kWh | (0.0008) |
| Rate Rider for Disposition of Account 1592 (Applicable to former Haldimand USL customers only) - effective until December 31, 2025 | $/kWh | (0.0007) |
| Rate Rider for Disposition of Account 1592 (Applicable to former Woodstock USL customers only) - effective until December 31, 2025 | $/kWh | (0.0003) |
| Retail Transmission Rate - Network Service Rate (see Note 4) | $/kWh | 0.0074 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate (see Note 5) | $/kWh | 0.0052 |

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR (see Note 12) | $/kWh | 0.0030 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers (see Note 12) | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) (see Note 12) | $/kWh | 0.0005 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Hydro One Networks Inc.
## TARIFF OF RATES AND CHARGES
### Effective and Implementation Date January 1, 2023
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**EB-2021-0110**

## SENTINEL LIGHTING SERVICE CLASSIFICATION

This classification is applicable to all Hydro One Networks' customers, including customers in former Norfolk Power Distribution Inc. and Haldimand County Hydro Inc. service areas who have separate service to a sentinel light. The energy consumption for sentinel lights is estimated based on Networks' profile for sentinel lighting load, which provides the amount of time each month that the sentinel lights are operating. Class B consumers are defined in accordance to O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor’s Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, in should be noted that the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

# Hydro One Networks Inc.
## TARIFF OF RATES AND CHARGES
### Effective and Implementation Date January 1, 2023
**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

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### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 3.01 |
| Base Rate Adjustment to Recover Past Tax Amounts (Applicable to Hydro One legacy customers only) (see Note 16) - effective until June 30, 2023 | $ | 0.14 |
| Distribution Volumetric Rate | $/kWh | 0.1658 |
| Base Rate Adjustment to Recover Past Tax Amounts (Applicable to Hydro One legacy customers only) (see Note 16) - effective until June 30, 2023 | $/kWh | 0.0078 |
| Rate Rider for Disposition of Group 1 Deferral/Variance Accounts (2023) - effective until December 31, 2025 | $/kWh | (0.0007) |
| Rate Rider for Disposition of Group 2 Deferral/Variance Accounts (2023) (Applicable to Hydro One legacy customers only) (see Note 16) - effective until December 31, 2025 | $/kWh | (0.0005) |
| Rate Rider for Disposition of Global Adjustment Account (2023) - effective until December 31, 2025 (see Note 13) | $/kWh | (0.0009) |
| Rate Rider for Disposition of Account 1595 (Applicable to former Norfolk Sentinel Light customers only) - effective until December 31, 2025 | $/kWh | (0.0005) |
| Rate Rider for Disposition of Account 1592 (Applicable to former Norfolk Sentinel Light customers only) - effective until December 31, 2025 | $/kWh | (0.0018) |
| Rate Rider for Disposition of Account 1592 (Applicable to former Haldimand Sentinel Light customers only) - effective until December 31, 2025 | $/kWh | (0.0055) |
| Retail Transmission Rate - Network Service Rate (see Note 4) | $/kWh | 0.0064 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate (see Note 5) | $/kWh | 0.0048 |

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR (see Note 12) | $/kWh | 0.0030 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers (see Note 12) | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) (see Note 12) | $/kWh | 0.0005 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Hydro One Networks Inc.
## TARIFF OF RATES AND CHARGES
### Effective and Implementation Date January 1, 2023
**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2021-0110**

## STREET LIGHTING SERVICE CLASSIFICATION

This classification is applicable to all Hydro One Networks' customers, including customers in former Norfolk Power Distribution Inc., Haldimand County Hydro Inc. and Woodstock Hydro Services Inc.'s service areas, who have streetlights, which are devices owned by or operated for a road authority and/or municipal corporation. The energy consumption for street lights is estimated based on Networks' profile for street lighting load, which provides the amount of time each month that the street lights are operating. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor’s Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, it should be noted that the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

# Hydro One Networks Inc.
## TARIFF OF RATES AND CHARGES
### Effective and Implementation Date January 1, 2023
**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2021-0110**

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 3.01 |
| Base Rate Adjustment to Recover Past Tax Amounts (Applicable to Hydro One legacy customers only) (see Note 16) - effective until June 30, 2023 | $ | 0.11 |
| Distribution Volumetric Rate | $/kWh | 0.1083 |
| Base Rate Adjustment to Recover Past Tax Amounts (Applicable to Hydro One legacy customers only) (see Note 16) - effective until June 30, 2023 | $/kWh | 0.0034 |
| Rate Rider for Disposition of Group 1 Deferral/Variance Accounts (2023) - effective until December 31, 2025 | $/kWh | (0.0007) |
| Rate Rider for Disposition of Group 2 Deferral/Variance Accounts (2023) (Applicable to Hydro One legacy customers only) (see Note 16) - effective until December 31, 2025 | $/kWh | (0.0004) |
| Rate Rider for Disposition of Global Adjustment Account (2023) - effective until December 31, 2025 (see Note 13) | $/kWh | (0.0009) |
| Rate Rider for Disposition of Account 1595 (Applicable to former Woodstock Street Light customers only) - effective until December 31, 2025 | $/kWh | 0.0001 |
| Rate Rider for Disposition of Account 1595 (Applicable to former Norfolk Street Light customers only) - effective until December 31, 2025 | $/kWh | (0.0004) |
| Rate Rider for Disposition of Account 1592 (Applicable to former Norfolk Street Light customers only) - effective until December 31, 2025 | $/kWh | (0.0011) |
| Rate Rider for Disposition of Account 1592 (Applicable to former Haldimand Street Light customers only) - effective until December 31, 2025 | $/kWh | (0.0028) |
| Rate Rider for Disposition of Account 1592 (Applicable to former Woodstock Street Light customers only) - effective until December 31, 2025 | $/kWh | (0.0013) |
| Retail Transmission Rate - Network Service Rate (see Note 4) | $/kWh | 0.0064 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate (see Note 5) | $/kWh | 0.0048 |

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR (see Note 12) | $/kWh | 0.0030 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers (see Note 12) | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) (see Note 12) | $/kWh | 0.0005 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Hydro One Networks Inc.
## TARIFF OF RATES AND CHARGES
### Effective and Implementation Date January 1, 2023
**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2021-0110**

## ACQUIRED RESIDENTIAL SERVICE CLASSIFICATIONS

These classifications apply to Residential and Seasonal properties in the service areas of former Norfolk Power, Haldimand county Hydro, and Woodstock Hydro, which are utilities acquired by Hydro One Networks after 2013. It may include additional buildings served through the same meter, provided they are not rental income units. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

# Hydro One Networks Inc.
## TARIFF OF RATES AND CHARGES
### Effective and Implementation Date January 1, 2023
**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2021-0110**

## ACQUIRED URBAN DENSITY - AUR

This classification applies to residential accounts in acquired service areas (after 2013) with urban density and currently includes customers in the former Woodstock Hydro Services Inc.'s service area.

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 30.17 |
| Smart Metering Entity Charge - effective until December 31, 2027 | $ | 0.42 |
| Rate Rider for Disposition of Account 1592 - effective until December 31, 2025 | $ | (0.40) |
| Rate Rider for Disposition of Group 1 Deferral/Variance Accounts (2023) - effective until December 31, 2025 | $/kWh | (0.0007) |
| Rate Rider for Disposition of Global Adjustment Account (2023) - effective until December 31, 2025 (see Note 13) | $/kWh | (0.0009) |
| Rate Rider for Disposition of Account 1595 - effective until December 31, 2025 | $/kWh | (0.0002) |
| Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2022) - effective until December 31, 2023 | $/kWh | 0.0003 |
| Retail Transmission Rate - Network Service Rate (see Note 4) | $/kWh | 0.0122 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate (see Note 5) | $/kWh | 0.0084 |

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR (see Note 12) | $/kWh | 0.0030 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers (see Note 12) | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) (see Note 12) | $/kWh | 0.0005 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Hydro One Networks Inc.
## TARIFF OF RATES AND CHARGES
### Effective and Implementation Date January 1, 2023
**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2021-0110**

## ACQUIRED MIXED DENSITY - AR

This classification applies to residential accounts in acquired service areas (after 2013) with mixed-density (that is, combination of Urban, Medium and Low density areas) and currently includes customers in the former Norfolk Power Distribution Inc. and Haldimand County Hydro Inc.'s service territories.

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 36.64 |
| Smart Metering Entity Charge - effective until December 31, 2027 | $ | 0.42 |
| Rate Rider for Disposition of Account 1592 (Applicable to former Norfolk Residential customers only) - effective until December 31, 2025 | $ | (0.43) |
| Rate Rider for Disposition of Account 1592 (Applicable to former Haldimand Residential customers only) - effective until December 31, 2025 | $ | (0.46) |
| Rate Rider for Disposition of Group 1 Deferral/Variance Accounts (2023) - effective until December 31, 2025 | $/kWh | (0.0007) |
| Rate Rider for Disposition of Global Adjustment Account (2023) - effective until December 31, 2025 (see Note 13) | $/kWh | (0.0009) |
| Rate Rider for Disposition of Account 1595 (Applicable to former Norfolk Residential customers only) - effective until December 31, 2025 | $/kWh | (0.0001) |
| Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (former Norfolk Residential Customers only) (2022) - effective until December 31, 2023 | $/kWh | 0.0004 |
| Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (former Haldimand Residential Customers only) (2022) - effective until December 31, 2023 | $/kWh | 0.0003 |
| Retail Transmission Rate - Network Service Rate (see Note 4) | $/kWh | 0.0116 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate (see Note 5) | $/kWh | 0.0081 |

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR (see Note 12) | $/kWh | 0.0030 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers (see Note 12) | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) (see Note 12) | $/kWh | 0.0005 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Hydro One Networks Inc.
## TARIFF OF RATES AND CHARGES
### Effective and Implementation Date January 1, 2023
**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2021-0110**

## ACQUIRED GENERAL SERVICE CLASSIFICATIONS

Acquired General Service classification applies to any service that does not fit the description of acquired residential classes. It includes combination type services where a variety of uses are made of the service by the owner of one property, and all multiple services except residential. Class A and Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor’s Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

If included in the following listing of monthly rates and charges, the rate rider for the disposition of WMS - Sub-account CBR Class B is not applicable to wholesale market participants (WMP), customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new Class B customers.

If included in the following listing of monthly rates and charges, the rate rider for the disposition of Global Adjustment is only applicable to non-RPP Class B customers. It is not applicable to WMP, customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new non-RPP Class B customers.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

# Hydro One Networks Inc.
## TARIFF OF RATES AND CHARGES
### Effective and Implementation Date January 1, 2023
**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2021-0110**

## ACQUIRED URBAN DENSITY GENERAL SERVICE ENERGY BILLED - AUGE

This classification applies to non-residential accounts in acquired service areas (after 2013) with urban density and currently includes customers located in former Woodstock Hydro Services Inc's service territory, whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW.

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 25.59 |
| Smart Metering Entity Charge - effective until December 31, 2027 | $ | 0.42 |
| Distribution Volumetric Rate | $/kWh | 0.0148 |
| Rate Rider for Disposition of Group 1 Deferral/Variance Accounts (2023) - effective until December 31, 2025 | $/kWh | (0.0007) |
| Rate Rider for Disposition of Global Adjustment Account (2023) - effective until December 31, 2025 (see Note 13) | $/kWh | (0.0009) |
| Rate Rider for Disposition of Account 1595 - effective until December 31, 2025 | $/kWh | (0.0002) |
| Rate Rider for Disposition of Account 1592 - effective until December 31, 2025 | $/kWh | (0.0003) |
| Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2022) - effective until December 31, 2023 | $/kWh | 0.0037 |
| Retail Transmission Rate - Network Service Rate (see Note 4) | $/kWh | 0.0094 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate (see Note 5) | $/kWh | 0.0068 |

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR (see Note 12) | $/kWh | 0.0030 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers (see Note 12) | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) (see Note 12) | $/kWh | 0.0005 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Hydro One Networks Inc.
## TARIFF OF RATES AND CHARGES
### Effective and Implementation Date January 1, 2023
**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2021-0110**

## ACQUIRED MIXED DENSITY GENERAL SERVICE ENERGY BILLED - AGSE

This classification applies to non-residential accounts in acquired service areas (after 2013) with mixed-density (that is, combination of Urban, Medium and Low density areas) and currently includes customers located in former Norfolk Power Distribution Inc. and Haldimand County Hydro Inc.'s service territories, whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW.

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 38.38 |
| Smart Metering Entity Charge - effective until December 31, 2027 | $ | 0.42 |
| Distribution Volumetric Rate | $/kWh | 0.0176 |
| Rate Rider for Disposition of Group 1 Deferral/Variance Accounts (2023) - effective until December 31, 2025 | $/kWh | (0.0007) |
| Rate Rider for Disposition of Global Adjustment Account (2023) - effective until December 31, 2025 (see Note 13) | $/kWh | (0.0009) |
| Rate Rider for Disposition of Account 1595 (Applicable to former Norfolk GS<50kW customers only) - effective until December 31, 2025 | $/kWh | (0.0001) |
| Rate Rider for Disposition of Account 1592 (Applicable to former Norfolk GS<50kW customers only) - effective until December 31, 2025 | $/kWh | (0.0004) |
| Rate Rider for Disposition of Account 1592 (Applicable to former Haldimand GS<50kW customers only) - effective until December 31, 2025 | $/kWh | (0.0004) |
| Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (former Norfolk GS<50kW Customers only) (2022) - effective until December 31, 2023 | $/kWh | 0.0081 |
| Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (former Haldimand GS<50kW Customers only) (2022) - effective until December 31, 2023 | $/kWh | (0.0002) |
| Retail Transmission Rate - Network Service Rate (see Note 4) | $/kWh | 0.0092 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate (see Note 5) | $/kWh | 0.0067 |

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR (see Note 12) | $/kWh | 0.0030 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers (see Note 12) | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) (see Note 12) | $/kWh | 0.0005 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Hydro One Networks Inc.
## TARIFF OF RATES AND CHARGES
### Effective and Implementation Date January 1, 2023
**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2021-0110**

## ACQUIRED URBAN DENSITY GENERAL SERVICE DEMAND BILLED - AUGD

This classification applies to non-residential accounts in acquired service areas (after 2013) with Urban density and currently includes customers located in former Woodstock Hydro Services Inc.'s service territory and whose average monthly maximum demand is equal to or greater than, or is forecast to be equal to or greater than, 50 kW. Hydro One establishes billing determinants for demand customers' Distribution charges at the greater of 100 per cent of kW and 90 per cent of kVA where kVA metering is installed. When a customer's power factor is known to be less than 90 per cent, a kVA meter of equivalent electronic meter shall be used for measuring and billing.

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 146.47 |
| Distribution Volumetric Rate | $/kW | 2.7207 |
| Rate Rider for Disposition of Group 1 Deferral/Variance Accounts (General) (2023) - effective until December 31, 2025 (see Note 9) | $/kW | (0.0975) |
| Rate Rider for Disposition of Group 1 Deferral/Variance Accounts (Non-WMP) (2023) - effective until December 31, 2025 (see Note 10) | $/kW | (0.1357) |
| Rate Rider for Disposition of Global Adjustment Account (2023) - effective until December 31, 2025 (see Note 13) | $/kWh | (0.0009) |
| Rate Rider for Disposition of Account 1595 - effective until December 31, 2025 | $/kW | 0.0327 |
| Rate Rider for Disposition of Account 1592 - effective until December 31, 2025 | $/kW | (0.0392) |
| Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2022) - effective until December 31, 2023 | $/kW | 0.6839 |
| Retail Transmission Rate - Network Service Rate (see Note 4) | $/kW | 3.1620 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate (see Note 5) | $/kW | 2.2698 |

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR (see Note 12) | $/kWh | 0.0030 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers (see Note 12) | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) (see Note 12) | $/kWh | 0.0005 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Hydro One Networks Inc.
## TARIFF OF RATES AND CHARGES
### Effective and Implementation Date January 1, 2023
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**EB-2021-0110**

## ACQUIRED MIXED DENSITY GENERAL SERVICE DEMAND BILLED - AGSD

This classification applies to non-residential accounts in acquired service areas (after 2013) with mixed-density (that is, combination of Urban, Medium and Low density areas) and currently includes customers located in former Norfolk Power Distribution Inc. and Haldimand County Hydro Inc.'s service territories and whose average monthly maximum demand is equal to or greater than, or is forecast to be equal to or greater than, 50 kW. Hydro One establishes billing determinants for demand customers' Distribution charges at the greater of 100 per cent of kW and 90 per cent of kVA where kVA metering is installed. When a customer's power factor is known to be less than 90 per cent, a kVA meter of equivalent electronic meter shall be used for measuring and billing.

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 170.26 |
| Distribution Volumetric Rate | $/kW | 4.4259 |
| Rate Rider for Disposition of Group 1 Deferral/Variance Accounts (General) (2023) - effective until December 31, 2025 (see Note 9) | $/kW | (0.0984) |
| Rate Rider for Disposition of Group 1 Deferral/Variance Accounts (Non-WMP) (2023) - effective until December 31, 2025 (see Note 10) | $/kW | (0.1369) |
| Rate Rider for Disposition of Global Adjustment Account (2023) - effective until December 31, 2025 (see Note 13) | $/kWh | (0.0009) |
| Rate Rider for Disposition of Account 1595 (Applicable to former Norfolk GS 50-4,999kW customers only) - effective until December 31, 2025 | $/kW | 0.0327 |
| Rate Rider for Disposition of Account 1592 (Applicable to former Norfolk GS 50-4,999kW customers only) - effective until December 31, 2025 | $/kW | (0.0618) |
| Rate Rider for Disposition of Account 1592 (Applicable to former Haldimand GS 50-4,999kW customers only) - effective until December 31, 2025 | $/kW | (0.0603) |
| Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (former Norfolk GS 50-4,999kW Customers only) (2022) - effective until December 31, 2023 | $/kW | 0.2853 |
| Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (former Haldimand GS 50-4,999kW Customers only) (2022) - effective until December 31, 2023 | $/kW | (0.0575) |
| Retail Transmission Rate - Network Service Rate (see Note 4) | $/kW | 2.7232 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate (see Note 5) | $/kW | 2.0040 |

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR (see Note 12) | $/kWh | 0.0030 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers (see Note 12) | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) (see Note 12) | $/kWh | 0.0005 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Hydro One Networks Inc.
## TARIFF OF RATES AND CHARGES
### Effective and Implementation Date January 1, 2023
**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2021-0110**

## MicroFIT SERVICE CLASSIFICATION

This classification applies to an electricity generation facility, located in Hydro One Networks Inc. service area as well as former Norfolk Power Distribution Inc., Haldimand County Hydro Inc. and Woodstock Hydro Services Inc.'s service areas, contracted under the Independent Electricity System Operator's microFIT program and connected to the distributor's distribution system. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 4.55 |

# Hydro One Networks Inc.
## TARIFF OF RATES AND CHARGES
### Effective and Implementation Date January 1, 2023
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**EB-2021-0110**

## ALLOWANCES

### CUSTOMER-SUPPLIED TRANSFORMATION ALLOWANCE
Applicable to customers providing their own transformers and the primary voltage is under 50 kV

| | | |
|---|---|---|
| Demand Billed - per kW of billing demand/month | $/kW | (0.60) |
| Energy Billed - per kWh of billing energy/month | $/kWh | (0.0014) |

### TRANFORMER LOSS ALLOWANCE
Applicable to non-ST customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side).

| | | |
|---|---|---|
| For installations up to and including bank capacity of 400 kVA | % | (1.50) |
| For bank capacities over 400 kVA | % | (1.00) |

Applicable to ST customers requiring a billing adjustment for transformer losses as the result of being metered on the secondary side of a transformer. The uniform value of 1% shall be added to measured demand and energy (as measured on the secondary side) to adjust for transformer losses.

Alternately, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly.

For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities.

## LOSS FACTORS

| | |
|---|---|
| Residential - UR | 1.057 |
| Residential - R1 | 1.076 |
| Residential - R2 | 1.105 |
| General Service - UGe | 1.067 |
| General Service - GSe | 1.096 |
| General Service - UGd | 1.050 |
| General Service - GSd | 1.061 |
| Distributed Generation - Dgen | 1.061 |
| Unmetered Scattered Load | 1.092 |
| Sentinel Lights | 1.092 |
| Street Lights | 1.092 |
| Acquired Residential - AUR | 1.043 |
| Acquired General Service - AUGe | 1.043 |
| Acquired General Service - AUGd | 1.033 |
| Acquired Residential - AR | 1.064 |
| Acquired General Service - AGSe | 1.064 |
| Acquired General Service - AGSd | 1.053 |
| Sub Transmission - ST | |
| Distribution Loss Factors | |
| Embedded Delivery Points (metering at station) | 1.000 |
| Embedded Delivery Points (metering away from station) | 1.028 |
| Total Loss Factors | |
| Embedded Delivery Points (metering at station) | 1.006 |
| Embedded Delivery Points (metering away from station) | 1.034 |

# Hydro One Networks Inc.
## TARIFF OF RATES AND CHARGES
### Effective and Implementation Date January 1, 2023
**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2021-0110**

# SPECIFIC SERVICE CHARGES

## APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

### Customer Administration

| | | |
|---|---|---|
| Easement letter - letter request | $ | 92.51 |
| Easement letter - web request | $ | 25.00 |
| Returned cheque charge | $ | 7.00 |
| Account set up charge/change of occupancy charge (plus credit agency costs, if applicable) | $ | 38.00 |
| Special meter reads (retailer requested off-cycle read) | $ | 90.00 |
| Meter dispute charge plus Measurement Canada fees (if meter found correct) | $ | 30.00 |

### Non-Payment of Account

| | | |
|---|---|---|
| Late payment - per month (effective annual rate 19.56% per annum or 0.04896% compounded daily rate) | % | 1.50 |
| Collection - reconnect at meter - during regular hours | $ | 65.00 |
| Collection - reconnect at meter - after regular hours | $ | 185.00 |
| Collection - reconnect at pole - during regular hours | $ | 185.00 |
| Collection - reconnect at pole - after regular hours | $ | 415.00 |

### Other

| | | |
|---|---|---|
| Service call - customer owned equipment - during regular hours | $ | 210.00* |
| Service call - customer owned equipment - after regular hours | $ | 775.00* |
| Specific charge for access to power poles - telecom | $ | 34.76 |
| Reconnect completed after regular hours (customer/contract driven) - at meter | $ | 245.00 |
| Reconnect completed after regular hours (customer/contract) driven) - at pole | $ | 475.00 |
| Additional service layout fee - basic/complex (more than one hour) | $ | 595.20 |
| Pipeline crossings | $ | 2,499.29 |
| Water crossings | $ | 3,717.21 |
| Railway crossings | $ | $4,965.66 plus Railway Feedthrough Costs |

# Hydro One Networks Inc.
## TARIFF OF RATES AND CHARGES
### Effective and Implementation Date January 1, 2023
**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2021-0110**

| | | |
|---|---|---|
| Overhead line staking per meter | $ | 4.42 |
| Underground line staking per meter | $ | 3.18 |
| Subcable line staking per meter | $ | 2.78 |
| Central metering - new service <45 kw | $ | 100.00 |
| Conversion to central metering <45 kw | $ | 1,612.75 |
| Conversion to central metering >=45 kw | $ | 1,512.75 |
| Connection impact assessments - net metering | $ | 3,329.86 |
| Connection impact assessments - embedded LDC generators | $ | 2,996.97 |
| Connection impact assessments - small projects <= 500 kw | $ | 3,405.38 |
| Connection impact assessments - small projects <= 500 kw, simplified | $ | 2,054.41 |
| Connection impact assessments - greater than capacity allocation exempt projects - capacity allocation required projects | $ | 9,011.83 |
| Connection impact assessments - greater than capacity allocation exempt projects - TS review for LDC capacity allocation required projects | $ | 5,969.89 |
| Specific charge for access to power poles - LDC | $ | see below |
| Specific charge for access to power poles - generators | $ | see below |
| Specific charge for access to power poles - municipal streetlights | $ | 2.04 |
| Sentinel light rental charge | $ | 10.00 |
| Sentinel light pole rental charge | $ | 7.00 |

*Base Charge only. Additional work on equipment will be based on actual costs.

Specific Charge for LDCs Access to the Power Poles ($/pole/year)

| | | |
|---|---|---|
| LDC rate for 10’ of power space | $ | 90.60 |
| LDC rate for 15’ of power space | $ | 108.72 |
| LDC rate for 20’ of power space | $ | 120.80 |
| LDC rate for 25’ of power space | $ | 129.43 |
| LDC rate for 30’ of power space | $ | 135.90 |
| LDC rate for 35’ of power space | $ | 140.93 |
| LDC rate for 40’ of power space | $ | 144.96 |
| LDC rate for 45’ of power space | $ | 148.25 |
| LDC rate for 50’ of power space | $ | 151.00 |
| LDC rate for 55’ of power space | $ | 153.32 |
| LDC rate for 60’ of power space | $ | 155.31 |

Specific Charge for Generator Access to the Power Poles ($/pole/year)

| | | |
|---|---|---|
| Generator rate for 10’ of power space | $ | 90.60 |
| Generator rate for 15’ of power space | $ | 108.72 |
| Generator rate for 20’ of power space | $ | 120.80 |
| Generator rate for 25’ of power space | $ | 129.43 |
| Generator rate for 30’ of power space | $ | 135.90 |
| Generator rate for 35’ of power space | $ | 140.93 |
| Generator rate for 40’ of power space | $ | 144.96 |
| Generator rate for 45’ of power space | $ | 148.25 |
| Generator rate for 50’ of power space | $ | 151.00 |
| Generator rate for 55’ of power space | $ | 153.32 |
| Generator rate for 60’ of power space | $ | 155.31 |

# Hydro One Networks Inc.
## TARIFF OF RATES AND CHARGES
### Effective and Implementation Date January 1, 2023
**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2021-0110**

## RETAIL SERVICE CHARGES (if applicable)

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

Retail Service Charges refer to services provided by a distributor to retailers or customers related to the supply of competitive electricity

| | | |
|---|---|---|
| One-time charge, per retailer, to establish the service agreement between the distributor and the retailer | $ | 107.68 |
| Monthly fixed charge, per retailer | $ | 43.08 |
| Monthly variable charge, per customer, per retailer | $ | 1.07 |
| Distributor-consolidated billing monthly charge, per customer, per retailer | $ | 0.64 |
| Retailer-consolidated billing monthly credit, per customer, per retailer | $ | (0.64) |
| Service Transaction Requests (STR) | | |
| Request fee, per request, applied to the requesting party | $ | 0.54 |
| Processing fee, per request, applied to the requesting party | $ | 1.07 |
| Request for customer information as outlined in Section 10.6.3 and Chapter 11 of the Retail Settlement Code directly to retailers and customers, if not delivered electronically through the Electronic Business Transaction (EBT) system, applied to the requesting party | | |
| Up to twice a year | $ | no charge |
| More than twice a year, per request (plus incremental delivery costs) | $ | 4.31 |
| Notice of switch letter charge, per letter (unless the distributor has opted out of applying the charge as per the Ontario Energy Board's Decision and Order EB-2015-0304, issued on February 14, 2019) | $ | 2.15 |

# Hydro One Networks Inc.
## TARIFF OF RATES AND CHARGES
### Effective and Implementation Date January 1, 2023
**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2021-0110**

**NOTES**

1. The basis of the charge is the customer's monthly maximum demand. For an ST customer with multiple delivery points served from the same Transformer Station or High Voltage Distribution Station, the aggregated demand will be the applicable billing determinant. Demand is not aggregated between stations.
2. The basis of the charge is kilometers of line, within the supplied LDC's service area, supplying solely that LDC.
3. The basis of the charge is the "non-coincident demand" at each delivery point of the customer supplied by the station. This is measured as the kW demand at the delivery point at the time in the month of maximum load on the delivery point. For a customer connected through two or more distribution stations, the total charge for the connection to the shared distribution stations is the sum of the relevant charges for each of the distribution stations.

4. The monthly billing determinant for the RTSR Network Service rate is:
   a. For energy-only metered customers: the customer's metered energy consumption adjusted by the total loss factor as approved by the Ontario Energy Board.
   b. For interval-metered customers: the peak demand from 7 AM to 7 PM (local time) on IESO business days in the billing period. The rates shown are to be adjusted by the total loss factor as approved by the Ontario Energy Board.
   c. For non-interval-metered demand billed customers: the non-coincident peak demand in the billing period. The rates shown are to be adjusted by the total loss factor as approved by the Ontario Energy Board.

5. The monthly billing determinant for the RTSR Line and Transformation Connection Service rates:
   a. For energy-only metered customers: the customer's metered energy consumption adjusted by the total loss factor as approved by the Ontario Energy Board.
   b. For all demand billed customers: the non-coincident peak demand in the billing period. The rates shown are to be adjusted by the total loss factor as approved by the Ontario Energy Board.
   c. For customers with load displacement generation above 1 MW, or 2 MW for renewable generation, installed after October 1998, RTSR connection is billed at the gross demand level.
6. Delivery point with respect to RTSR is defined as the low side of the Transformer Station that steps down voltage from above 50 kV to below 50 kV. For customer with multiple interval-metered delivery points served from the same Transformer Station, the aggregated demand at the said delivery points on the low side of the Transformer Station will be the applicable billing determinant.
7. The loss factors, and which connection service rates are applied, are determined based on the point at which the distribution utility or customer is metered for its connection to Hydro One Distribution's system. Hydro One Distribution's connection agreements with these distribution utilities and customers will establish the appropriate loss factors and connection rates to apply from Hydro One Distribution's tariff schedules.
8. The Common ST Lines rate also applies to Distributors which use lines in the 12.5 kV to 4.16 kV range from HVDSs or LVDSs.
9. Rate Rider for Disposition of Group 1 Deferral/Variance Accounts (General) is charged based on appropriate billing kW.
10. Rate Rider for Disposition of Group 1 Deferral/Variance Account (non-WMP) applies to non-WMP Class A or Class B customers.

11. The Meter charge is applied per metering facility at delivery points for which Hydro One owns the metering.
12. The Wholesale Market Service Rate and the Rural or Remote Electricity Rate Protection Charge are applied solely to non-Wholesale Market Participants. For Class A customers, distributors shall bill the actual CBDR costs to Class A customers in proportion to their contribution to peak. These rates pertain to the IESO's defined point of sale; consequently, appropriate loss factors as approved by the Ontario Energy Board must be applied to the customers metered energy.
13. The Global Adjustment rate rider applies to metered energy consumption, as approved by the Ontario Energy Board, for non-LDC, non-RPP and Class B customers that are charged Wholesale Market Service Charges by Hydro One Distribution.
14. For customers with load displacement generation at 1MW or above, or 2MW or above for renewable generation, installed after October 1998, the ST volumetric charges are billed at the gross demand level.
15. Local Transformation Charge applies to customers in the ST class who make use of Hydro One owned local transformation facilities.
16. Legacy customers are Hydro One Networks Inc. customers located outside the service areas of former Norfolk Power Distribution Inc., Haldimand County Hydro Inc., Woodstock Hydro Services Inc., Orillia Power Distribution Corporation, and Peterborough Distribution Inc..

# ATTACHMENT 3

## ACCOUNTING ORDERS

# HYDRO ONE TRANSMISSION ACCOUNTING ORDER
# ACCOUNT 1508 – OTHER REGULATORY ASSETS, SUB-ACCOUNT CAPITALIZED OVERHEADS TAX VARIANCE ACCOUNT

Hydro One Transmission proposes the establishment of a new Account 1508 – Other Regulatory Assets, Sub-Account "Capitalized Overhead Tax Variance Account" to record the revenue requirement impact associated with the net incremental tax benefits arising from additional capitalized overheads deductions for the 2016-2022 period as a result of Hydro One amending its prior tax returns or filing the future returns based on the new tax filing position (the Updated Approach). Amounts will be recorded at the earlier of (i) when the tax return of a particular year is audited by the CRA and the new filing position is accepted as filed or (ii) when the taxation year becomes statute barred.

This account will also capture variances in the revenue requirement associated with CRA reassessments with respect to net incremental tax benefits from the Updated Approach that have been incorporated in the OEB approved revenue requirement for 2023 to 2027 as described in Exhibit G-01-02, Section 4.1.

This account will be established as Account 1508, Other Regulatory Assets – Sub-Account "Capitalized Overhead Tax Variance Account" effective January 1, 2023. Hydro One Transmission will record interest on the balance in the sub-account using the interest rates as set by the OEB. Simple interest will be calculated on the opening monthly balance of the account until the balance is fully disposed of.

The following outlines the proposed accounting entries for the deferral account.

| USofA# | Account Description |
|---|---|
| DR. 4110 | Transmission Services Revenue |
| CR. 1508 | Other Regulatory Assets, Sub-Account "Capitalized Overhead Variance Account" |

To record the benefits to be returned to rate-payers to the extent the CRA accepts the Updated Approach for the 2016 to 2022 period.

| | |
|---|---|
| DR. 6035 | Other Interest Expense |
| CR. 1508 | Other Regulatory Assets, Sub-Account "Capitalized Overhead Variance Account" |

To record interest improvement on the principal balance of the Capitalized Overhead Variance Account.

OR

| USofA# | Account Description |
|---|---|
| DR. 1508 | Other Regulatory Assets, Sub-Account "Capitalized Overhead Variance Account" |
| CR. 4110 | Transmission Services Revenue |

To record the benefits to be collected from rate-payers to the extent the CRA reassesses the Capital Overheads deductions currently incorporated into the proposed Transmission revenue requirements for the 2023 to 2027 period.

| | |
|---|---|
| DR. 1508 | Other Regulatory Assets, Sub-Account "Capitalized Overhead Variance Account" |
| CR. 6035 | Other Interest Expense |

To record interest improvement on the principal balance of the Capitalized Overhead Variance Account.

# HYDRO ONE TRANSMISSION ACCOUNTING ORDER
# ACCOUNT 1508– OTHER REGULATORY ASSETS, SUB-ACCOUNT EXTERNALLY DRIVEN TRANSMISSION PROJECTS VARIANCE ACCOUNT

Hydro One Transmission proposes the establishment of a new Account 1508 - Other Regulatory Assets, Sub-Account "Externally Driven Transmission Projects Variance Account" to record the revenue requirement impact including tax, if any, of variances between the in-service additions embedded in Hydro One's approved revenue requirement relating to mandatory transmission construction, expansion, reinforcement, modification and relocation work required by governmental authorities, including indirectly through agencies, Crown corporations, or similar parties through regulation, policy changes or other official directives (Externally Driven Work) and the actual in-service additions arising from Externally Driven Work during the 2023-2027 rate period.[1] This account shall not include Externally Driven Work that is expected to be owned and included in the rate base of any new partnership affiliated with Hydro One Transmission, as those amounts would instead be recorded in the Affiliate Transmission Projects Account.

As a symmetrical account, the variation in the Externally Driven Work relative to what is recovered in revenue requirement will be recorded in the account, with underspend returned to ratepayers and overspend to be recovered from ratepayers.

The account will be established as Account 1508, Other Regulatory Assets – Sub-Account "Externally Driven Transmission Projects Variance Account" effective January 1, 2023. Hydro One Transmission will record interest on the balance in the sub-account using the interest rates set by the OEB. Simple interest will be calculated on the opening monthly balance of the account until the balance is fully disposed.

The following outlines the proposed accounting entries for this variance account.

| USofA # | Account Description |
|---|---|
| DR/CR 4110 | Transmission Services Revenue |
| CR/DR 1508 | Other Regulatory Assets, Sub-Account "Externally Driven Transmission Projects Variance Account" |

Initial entry to record the revenue requirement impact of variances between Externally Driven Work in-service additions included in the forecast and actuals.

[1] The Externally Driven Work projects and amounts are referenced in the Settlement Agreement under Issue 29.

| USofA # | Account Description |
| --- | --- |
| DR/CR 6035 | Other Interest Expense |
| CR/DR 1508 | Other Regulatory Assets, Sub-Account "Externally Driven Transmission Projects Variance Account" |

To record interest improvement on the principal balance of the Externally Driven Transmission Projects Variance Account.

# HYDRO ONE TRANSMISSION ACCOUNTING ORDER
# ACCOUNT 2405 – OTHER REGULATORY LIABILITIES, SUB-ACCOUNT RIGHTS PAYMENTS VARIANCE ACCOUNT

Hydro One Transmission proposes a continuation of the currently established Account 2405 - Other Regulatory Liabilities, Sub-Account “Rights Payments Variance Account” subject to a modification, to capture the difference between forecast rights payments underlying the 2023-2027 period, and the actual rights payments incurred by Hydro One Transmission. Rights payments shall include the following: 1) Payments of fees under agreements or permits with railway companies and government entities for rights to cross and/or occupy their properties; 2) Payments of annual rental fees under permits and agreements from or with the Department of Indian and Northern Affairs Canada, through which Hydro One had approvals for its lines and stations to cross and/or occupy First Nation Reserves; and 3) Payments required to obtain all required consents necessary (including Long Term Relationship Agreements or similar, regardless of how those payments are characterized or their form) to complete the transfer of title to Hydro One for lands relating to transmission lines.[1]

The modified account will be established as Account 2405 - Other Regulatory Liabilities, Sub-Account “Rights Payments Variance Account” effective January 1, 2023. Hydro One Transmission will record interest on the balance in the sub-account using the interest rates set by the OEB. Simple interest will be calculated on the opening monthly balance of the account until the balance is fully disposed.

The following outlines the proposed accounting entries for this variance account.

| USofA # | Account Description |
|---|---|
| DR/CR 4110 | Transmission Services Revenue |
| CR/DR 2405 | Other Regulatory Liabilities, Sub-Account “Rights Payments Variance Account” |

Initial entry to record the difference between forecast rights payments, and actual rights payments.

| USofA # | Account Description |
|---|---|
| DR/CR 6035 | Other Interest Expense |
| CR/DR 2405 | Other Regulatory Liabilities, Sub-Account “Rights Payments Variance Account” |

To record interest improvement on the principal balance of the Rights Payments Variance Account.

[1] This third condition is the modification to the account.

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# HYDRO ONE TRANSMISSION ACCOUNTING ORDER
# ACCOUNT 2405 – OTHER REGULATORY LIABILITIES, SUB-ACCOUNT SALE OF PROPERTIES DEFERRAL ACCOUNT

Hydro One Transmission proposes the establishment of a new Account 2405 – Other Regulatory Liabilities, Sub-Account "Sale of Properties Deferral Account". The account will include two sub-accounts:

1. A Revenue Requirement Impacts sub-account to record the revenue requirement impact, including taxes, associated with the rate base component of the sold land and buildings in the General Plant Facilities and Real Estate portfolio, which are being recovered in rates but no longer owned by Hydro One during all or part of the 2023-2027 Custom IR term.

2. A Gain/Loss on Sale sub-account to record the after-tax gains or losses from the sale of land and buildings in the General Plant Facilities and Real Estate portfolio recovered in rates, during the 2023-2027 Custom IR term.

This account will be established as Account 2405, Other Regulatory Liabilities – Sub-Account "Sale of Properties Deferral Account" effective January 1, 2023. Hydro One Transmission will record interest on the balance in the sub-accounts using the interest rates as set by the OEB. Simple interest will be calculated on the opening monthly balance of the account until the balance is fully disposed of.

The following outlines the proposed accounting entries for the deferral account.

| USofA# | Account Description |
|---|---|
| DR 4110 | Transmission Services Revenue |
| CR 2405 | Other Regulatory Liabilities, Sub-Account "Sale of Properties Deferral Account – Revenue Requirement Impacts" |

To record the revenue requirement impact associated with the rate base component of the sold land and buildings in the General Plant Facilities and Real Estate portfolio.

| USofA# | Account Description |
|---|---|
| DR 6035 | Other Interest Expense |
| CR 2405 | Other Regulatory Liabilities, Sub-Account "Sale of Properties Deferral Account – Revenue Requirement Impacts" |

To record interest improvement on the principal balance of the Sale of Properties Deferral Account - Revenue Requirement Impacts.

| USofA# | Account Description |
|---|---|
| DR/CR 4355 | Gain on Disposition of Utility and Other Property |
| CR/DR 2405 | Other Regulatory Liabilities, Sub-Account “Sale of Properties Deferral Account – Gain/Loss on Sale” |

To record the after-tax gains or losses from the sale of existing land and buildings in the General Plant Facilities and Real Estate portfolio.

| USofA# | Account Description |
|---|---|
| DR/CR 6035 | Other Interest Expense |
| CR/DR 2405 | Other Regulatory Liabilities, Sub-Account “Sale of Properties Deferral Account – Gain/Loss on Sale” |

To record interest improvement on the principal balance of the Sale of Properties Deferral Account – Gain/Loss on Sale.

# HYDRO ONE TRANSMISSION ACCOUNTING ORDER
# ACCOUNT 2405 – OTHER REGULATORY LIABILITIES, SUB-ACCOUNT CLEAN ENERGY TAX CREDIT DEFERRAL ACCOUNT

Hydro One Transmission proposes the establishment of a new Account 2405 – Other Regulatory Liabilities, Sub-Account "Clean Energy Tax Credit Deferral Account" to record the revenue requirement impacts of eligible new tax credits associated with investments in net-zero technologies, battery storage solutions and clean hydrogen that may be established by the Government of Canada, as contemplated in p. 94 of the 2022 Federal Budget issued on April 7, 2022.[1] The account balance will be brought forth for disposition in a future rate application.

This account will be established as Account 2405, Other Regulatory Liabilities – Sub-Account "Clean Energy Tax Credit Deferral Account" with an effective date aligned with what would be stipulated in the 2022 Federal Budget. Hydro One Transmission will record interest on the balance in the sub-account using the interest rates as set by the OEB. Simple interest will be calculated on the opening monthly balance of the account until the balance is fully disposed of.

The following outlines the proposed accounting entries for the deferral account.

| USofA# | Account Description |
|---|---|
| DR. 4110 | Transmission Services Revenues |
| CR. 2405 | Other Regulatory Liabilities, Sub-Account "Clean Energy Tax Credit Deferral Account" |

To record the revenue requirement impacts of the tax credit benefits to be returned to ratepayers.

| | |
|---|---|
| DR. 6035 | Other Interest Expense |
| CR. 2405 | Other Regulatory Liabilities, Sub-Account "Clean Energy Tax Credit Deferral Account" |

To record interest improvement on the principal balance of the Clean Energy Tax Credit Deferral Account.

[1] https://budget.gc.ca/2022/home-accueil-en.html

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# HYDRO ONE TRANSMISSION ACCOUNTING ORDER
# ACCOUNT 1522 – PENSION/OPEB FORECAST ACCRUAL VERSUS ACTUAL CASH PAYMENT DIFFERENTIAL

Hydro One Transmission proposes the establishment of a modified Account 1522 – OPEB Forecast Accrual versus Actual Cash Payment Differential Account to track the differences between the forecast accrual amounts recovered in rates and the actual cash payments made for OPEBs. Hydro One Transmission's Account 1522 applies a modified approach from the OEB's Report on the Regulatory Treatment of Pension and OPEB Costs (EB-2015-0040) such that actual OPEB amounts recovered in rates includes both OM&A as well as capitalized OPEB amounts reflected in the form of total estimated depreciation expense.[1] All other aspects of Account 1522 remain consistent with the OEB's Report on the Regulatory Treatment of Pension and OPEB Costs. This account shall have three sub-accounts:

1. Pension/OPEB Forecast Accrual versus Actual Cash Payment Differential
2. Pension/OPEB Forecast Accrual versus Actual Cash Payment Differential Contra Account
3. OPEB Asymmetrical Carrying Charge Variance Account

The modified account will be established as Account 1522 – OPEB Forecast Accrual versus Actual Cash Payment Differential Account effective January 1, 2018. Hydro One Transmission will record the carrying charges interest on the primary sub-account using the interest rates set by the OEB. Simple interest will be calculated on the opening monthly balance of the primary sub-account until the balance is fully disposed. The interest rate shall be the CWIP rate prescribed by the OEB.

The following outlines the proposed accounting entries for this variance account.

| USofA # | Account Description |
|---|---|
| DR 1522 | OPEB Forecast Accrual versus Actual Cash Payment Differential Account |
| CR 1522 | OPEB Forecast Accrual versus Actual Cash Payment Differential Contra Account |

To track the difference between the total OPEB accrual amount approved in rates and the actual cash amount paid.

[1] Refer to Exhibit G-01-02, Sections 4.5 and 4.6 for further details

| USofA # | Account Description |
|---|---|
| DR 6035 | Other Interest Expense |
| CR 1522 | OPEB Asymmetrical Carrying Charge Variance Account |

To record the carrying charge on the OPEB Forecast Accrual versus Actual Cash Payment Differential sub-account.

# HYDRO ONE DISTRIBUTION ACCOUNTING ORDER
# ACCOUNT 1508 – OTHER REGULATORY ASSETS, SUB-ACCOUNT CAPITALIZED OVERHEADS TAX VARIANCE ACCOUNT

Hydro One Distribution proposes the establishment of a new Account 1508 – Other Regulatory Assets, Sub-Account "Capitalized Overhead Tax Variance Account" to record the revenue requirement impact associated with the net incremental tax benefits arising from additional capitalized overheads deductions for the 2016-2022 period as a result of Hydro One amending its prior tax returns or filing the future returns based on the new tax filing position (the Updated Approach). Amounts will be recorded at the earlier of (i) when the tax return of a particular year is audited by the CRA and the new filing position is accepted as filed or (ii) when the taxation year becomes statute barred.

This account will also capture variances in the revenue requirement associated with CRA reassessments with respect to the capitalized overhead tax benefits that have been incorporated in the OEB approved revenue requirement for 2023 to 2027 as described in Exhibit G-01-02, Section 7.1.

This account will be established as Account 1508, Other Regulatory Assets – Sub-Account "Capital Overhead Tax Variance Account" effective January 1, 2023. Hydro One Distribution will record interest on the balance in the sub-account using the interest rates as set by the OEB. Simple interest will be calculated on the opening monthly balance of the account until the balance is fully disposed of.

The following outlines the proposed accounting entries for the deferral account.

| <u>USofA#</u> | <u>Account Description</u> |
|---|---|
| DR. 4080 | Distribution Services Revenue |
| CR. 1508 | Other Regulatory Assets, Sub-Account "Capitalized Overhead Variance Account" |

To record the benefits to be returned to rate-payers to the extent the CRA <u>accepts</u> the new tax filing position from 2016 to 2022.

| | |
|---|---|
| DR. 6035 | Other Interest Expense |
| CR. 1508 | Other Regulatory Assets, Sub-Account "Capitalized Overhead Variance Account" |

To record interest improvement on the principal balance of the Capitalized Overhead Variance Account.

OR

| <u>USofA#</u> | <u>Account Description</u> |
|---|---|
| DR. 1508 | Other Regulatory Assets, Sub-Account “Capitalized Overhead Variance Account” |
| CR. 4080 | Distribution Services Revenue |

To record the benefits to be collected from rate-payers to the extent the CRA <u>reassess</u> the Capital Overheads deductions currently incorporated into the proposed Distribution revenue requirements for the 2023 to 2027 period.

| | |
|---|---|
| DR. 1508 | Other Regulatory Assets, Sub-Account “Capitalized Overhead Variance Account” |
| CR. 6035 | Other Interest Expense |

To record interest improvement on the principal balance of the Capitalized Overhead Variance Account.

# HYDRO ONE DISTRIBUTION ACCOUNTING ORDER
# ACCOUNT 1508 – OTHER REGULATORY ASSETS, SUB-ACCOUNT EXTERNALLY DRIVEN DISTRIBUTION PROJECTS VARIANCE ACCOUNT

Hydro One Distribution proposes the establishment of a new Account 1508 - Other Regulatory Assets, Sub-Account "Externally Driven Distribution Projects Variance Account" to record the revenue requirement impact, including tax, of overspending or underspending relative to Hydro One's distribution capital investment plan which underlies the proposed revenue requirement for the 2023-2027 rate period, where such overspending or underspending is for work related to 1) Joint Use and Relocations (D-SA-01), and 2) Variances in relation to Custom Demand DER (D-SA-03) updates or DER connections, but only triggered by specific IESO procurement initiatives.[1]

As a symmetrical account, the variation in externally driven investments relative to what is recovered in revenue requirement will be recorded in the account, with underspend returned to ratepayers and overspend to be recovered from ratepayers.

The account will be established as Account 1508, Other Regulatory Assets – Sub-Account "Externally Driven Distribution Projects Variance Account" effective January 1, 2023. Hydro One Distribution will record interest on the balance in the sub-account using the interest rates set by the OEB. Simple interest will be calculated on the opening monthly balance of the account until the balance is fully disposed.

The following outlines the proposed accounting entries for this variance account.

| USofA # | Account Description |
|---|---|
| DR/CR 4080 | Distribution Services Revenue |
| CR/DR 1508 | Other Regulatory Assets, Sub-Account "Externally Driven Distribution Projects Variance Account" |

Initial entry to record the revenue requirement impact of variances between externally driven distribution projects in-service additions included in the forecast and actuals.

[1] The Externally Driven Work projects and amounts are referenced in the Settlement Agreement under Issue 29.

| USofA # | Account Description |
| --- | --- |
| DR/CR 6035 | Other Interest Expense |
| CR/DR 1508 | Other Regulatory Assets, Sub-Account “Externally Driven Distribution Projects Variance Account” |

To record interest improvement on the principal balance of the Externally Driven Distribution Projects Variance Account.

# HYDRO ONE DISTRIBUTION ACCOUNTING ORDER
# ACCOUNT 1508 – OTHER REGULATORY ASSETS, SUB-ACCOUNT DISTRIBUTION CONNECTION COST AGREEMENT (CCA) VARIANCE ACCOUNT

Hydro One Distribution proposes the establishment of a new Account 1508 – Other Regulatory Assets, Sub-Account "Distribution Connection Cost Agreement (CCA) Variance Account" to track the impacts on the Distribution revenue requirement inclusive of tax relating to capital contribution true-ups paid by Hydro One Distribution to Hydro One Transmission, and the capital contributions collected by Hydro One Distribution from its embedded distributors and large customers, in accordance with amendments made to the Distribution System Code in 2018.

The account will be established as Account 1508 – Other Regulatory Assets, Sub-Account "Distribution Connection Cost Agreement (CCA) Variance Account" effective January 1, 2023. Hydro One Distribution will record interest on the balance in the sub-account using the interest rates set by the OEB. Simple interest will be calculated on the opening monthly balance of the account until the balance is fully disposed.

The following outlines the proposed accounting entries for this deferral account.

| USofA # | Account Description |
|---|---|
| CR/DR 4080 | Distribution Services Revenue |
| DR/CR 1508 | Other Regulatory Assets, Sub-Account "Distribution CCA Variance Account" |

Initial entry to record into the Distribution CCA variance account.

| USofA # | Account Description |
|---|---|
| CR/DR 6035 | Other Interest Expense |
| DR/CR 1508 | Other Regulatory Assets, Sub-Account "Distribution CCA Variance Account" |

To record interest improvement on the principal balance of the Distribution CCA variance account.

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# HYDRO ONE DISTRIBUTION ACCOUNTING ORDER
# ACCOUNT 2405 – OTHER REGULATORY LIABILITIES, SUB-ACCOUNT ADVANCED METERING INFRASTRUCTURE (AMI) 2.0 VARIANCE ACCOUNT

Hydro One Distribution proposes the establishment of a new Account 2405 - Other Regulatory Liabilities, Sub-Account "Advanced Metering Infrastructure (AMI) 2.0 Variance Account" to record the difference in revenue requirement impact including tax, if any, between the planned in-service additions included in the forecasted costs ($581M[1]) of the AMI 2.0 program over the 2023-2027 period and the actual in-service additions achieved as part of the AMI 2.0 program over the 2023-2027 period. The account will capture the revenue requirement impact of both costs and timing difference of the in-service additions over the 2023-2027 period. This account will be asymmetrical to the benefit of ratepayers.

The account will be established as Account 2405, Other Regulatory Liabilities – Sub-Account "AMI 2.0 Variance Account" effective January 1, 2023. Hydro One Distribution will record interest on the balance in the sub-account using the interest rates set by the OEB. Simple interest will be calculated on the opening monthly balance of the account until the balance is fully disposed.

The following outlines the proposed accounting entries for this variance account.

| UsofA # | Account Description |
|---|---|
| DR. 4080 | Distribution Services Revenue |
| CR. 2405 | Other Regulatory Liabilities – Sub-Account "AMI 2.0 Variance Account" |

Initial entry to record the revenue requirement impact difference between the planned in-service additions for AMI 2.0 and actual in-service additions for AMI 2.0.

| UsofA # | Account Description |
|---|---|
| DR. 6035 | Other Interest Expense |
| CR. 2405 | Other Regulatory Liabilities – Sub-Account "AMI 2.0 Variance Account" |

To record interest improvement on the principal balance of the AMI 2.0 Variance Account.

[1] As per the Settlement Agreement, p. 32

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# HYDRO ONE DISTRIBUTION ACCOUNTING ORDER ACCOUNT 2405 – OTHER REGULATORY LIABILITIES, SUB-ACCOUNT DEPRECIATION EXPENSE (ASSET REMOVAL COSTS) ASYMMETRICAL CUMULATIVE VARIANCE ACCOUNT

Hydro One Distribution proposes the establishment of a new Account 2405 – Other Regulatory Liabilities, Sub-Account "Depreciation Expense (Asset Removal Costs) Asymmetrical Cumulative Variance Account" to record the difference between the revenue requirement (including tax impact, if any) associated with asset removal costs forecasts that have been included in the proposed depreciation expenses for 2023-2027 and actual asset removal costs incurred in each of the test years. The account calculation will be cumulative by the end of 2027 – the account balance will be brought forward for disposition in a future rate application in the event that there is an over collection on a cumulative basis over the 2023 to 2027 period. This account will be asymmetrical to the benefit of ratepayers – if the actual asset removal costs are lower than the forecasted asset removal costs, Hydro One Distribution will return the difference to ratepayers.

The account will be established as Account 2405, Other Regulatory Liabilities – Sub-Account "Asset Removal Costs Asymmetrical Cumulative Variance Account" effective January 1, 2023. Hydro One Distribution will record interest on the balance in the sub-account using the interest rates set by the OEB. Simple interest will be calculated on the opening monthly balance of the account until the balance is fully disposed.

The following outlines the proposed accounting entries for this variance account.

| UsofA # | Account Description |
|---|---|
| DR. 4080 | Distribution Services Revenue |
| CR. 2405 | Other Regulatory Liabilities – Sub-Account "Asset Removal Costs Asymmetrical Cumulative Variance Account" |

Initial entry to record the difference between actual asset removal costs and forecasted asset removal costs.

| UsofA # | Account Description |
|---|---|
| DR. 6035 | Other Interest Expense |
| CR. 2405 | Other Regulatory Liabilities – Sub-Account "Asset Removal Costs Asymmetrical Cumulative Variance Account" |

To record interest improvement on the principal balance of the Asset Removal Costs Asymmetrical Cumulative Variance Account.

# HYDRO ONE DISTRIBUTION ACCOUNTING ORDER
# ACCOUNT 2405 – OTHER REGULATORY LIABILITIES, SUB-ACCOUNT SALE OF PROPERTIES DEFERRAL ACCOUNT

Hydro One Distribution proposes the establishment of a new Account 2405 – Other Regulatory Liabilities, Sub-Account "Sale of Properties Deferral Account". The account will include two sub-accounts:

1. A Revenue Requirement Impacts sub-account to record the revenue requirement impact, including taxes, associated with the rate base component of the sold land and buildings in the General Plant Facilities and Real Estate portfolio, which are being recovered in rates but no longer owned by Hydro One during all or part of the 2023-2027 Custom IR term.

2. A Gain/Loss on Sale sub-account to record the after-tax gains or losses from the sale of land and buildings in the General Plant Facilities and Real Estate portfolio recovered in rates, during the 2023-2027 Custom IR term.

This account will be established as Account 2405, Other Regulatory Liabilities – Sub-Account "Sale of Properties Deferral Account" effective January 1, 2023. Hydro One Distribution will record interest on the balance in the sub-accounts using the interest rates as set by the OEB. Simple interest will be calculated on the opening monthly balance of the account until the balance is fully disposed of.

The following outlines the proposed accounting entries for the deferral account.

| UsofA# | Account Description |
|---|---|
| DR 4080 | Distribution Services Revenue |
| CR 2405 | Other Regulatory Liabilities, Sub-Account "Sale of Properties Deferral Account – Revenue Requirement Impacts" |

To record the revenue requirement impact associated with the rate base component of the sold land and buildings in the General Plant Facilities and Real Estate portfolio.

| UsofA# | Account Description |
|---|---|
| DR 6035 | Other Interest Expense |
| CR 2405 | Other Regulatory Liabilities, Sub-Account "Sale of Properties Deferral Account – Revenue Requirement Impacts" |

To record interest improvement on the principal balance of the Sale of Properties Deferral Account – Revenue Requirement Impacts.

| UsofA# | Account Description |
|---|---|
| DR/CR 4355 | Gain on Disposition of Utility and Other Property |
| CR/DR 2405 | Other Regulatory Liabilities, Sub-Account "Sale of Properties Deferral Account – Gain/Loss on Sale" |

To record the after-tax gains or losses from the sale of existing land and buildings in the General Plant Facilities and Real Estate portfolio.

| UsofA# | Account Description |
|---|---|
| DR/CR 6035 | Other Interest Expense |
| CR/DR 2405 | Other Regulatory Liabilities, Sub-Account "Sale of Properties Deferral Account – Gain/Loss on Sale" |

To record interest improvement on the principal balance of the Sale of Properties Deferral Account – Gain/Loss on Sale.

# HYDRO ONE DISTRIBUTION ACCOUNTING ORDER ACCOUNT 2405 – OTHER REGULATORY LIABILITIES, SUB-ACCOUNT CLEAN ENERGY TAX CREDIT DEFERRAL ACCOUNT

Hydro One Distribution proposes the establishment of a new Account 2405 – Other Regulatory Liabilities, Sub-Account "Clean Energy Tax Credit Deferral Account" to record the revenue requirement impacts of eligible new tax credits associated with investments in net-zero technologies, battery storage solutions and clean hydrogen that may be established by the Government of Canada, as contemplated at p. 94 of the 2022 Federal Budget issued on April 7, 2022[1].The account balance will be brought forth for disposition in a future rate application.

This account will be established as Account 2405, Other Regulatory Liabilities – Sub-Account "Clean Energy Tax Credit Deferral Account" with an effective date aligned with what would be stipulated in the 2022 Federal Budget. Hydro One Distribution will record interest on the balance in the sub-account using the interest rates as set by the OEB. Simple interest will be calculated on the opening monthly balance of the account until the balance is fully disposed of.

The following outlines the proposed accounting entries for the deferral account.

| USofA# | Account Description |
|---|---|
| DR. 4080 | Distribution Services Revenue |
| CR. 2405 | Other Regulatory Liabilities, Sub-Account "Clean Energy Tax Credit Deferral Account" |

To record the revenue requirement impacts of the tax credit benefits to be returned to ratepayers.

| | |
|---|---|
| DR. 6035 | Other Interest Expense |
| CR. 2405 | Other Regulatory Liabilities, Sub-Account "Clean Energy Tax Credit Deferral Account" |

To record interest improvement on the principal balance of the Clean Energy Tax Credit Deferral Account.

[1] https://budget.gc.ca/2022/home-accueil-en.html

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# HYDRO ONE DISTRIBUTION ACCOUNTING ORDER ACCOUNT 2405 – OTHER REGULATORY LIABILITIES, SUB-ACCOUNT DISTRIBUTION SYSTEM ENERGY STORAGE – GRID SCALE THIRD-PARTY ACCOUNTING TREATMENT VARIANCE ACCOUNT

Hydro One Distribution proposes the establishment of a new Account 2405 – Other Regulatory Liabilities, Sub-Account "Distribution System Energy Storage – Grid Scale Third-Party Accounting Treatment Variance Account" to record the difference in the revenue requirement impact between Hydro One's current accounting treatment of the forecast costs as set out in the D-SS-04 for a grid scale energy storage project, and any alternative accounting treatment informed by any future OEB guidance pertaining to cost recovery for innovative solutions, if Hydro One enters into an arrangement with a third-party to provide reliability services. Amounts recorded in the account, including the consideration of alternative accounting treatment, informed by OEB guidance on this matter, if Hydro One enters into any third-party reliability services, will be considered and reviewed at Hydro One's next cost-based rate application. Hydro One will track amounts related to the grid scale energy storage solution project at a sufficiently detailed level to allow for that assessment.

The account will be established as Account 2405 – Other Regulatory Liabilities, Sub-Account "Distribution System Energy Storage – Grid Scale Third-Party Accounting Treatment Variance Account" effective January 1, 2023. Hydro One Distribution will record interest on the balance in the sub-account using the interest rates set by the OEB. Simple interest will be calculated on the opening monthly balance of the account until the balance is fully disposed.

The following outlines the proposed accounting entries for this deferral account.

| USofA # | Account Description |
|---|---|
| CR/DR 4080 | Distribution Services Revenue |
| DR/CR 2405 | Other Regulatory Liabilities, Sub-Account "Distribution System Energy Storage – Grid Scale Variance Account" |

Initial entry to record into the Distribution System Energy Storage – Grid Scale Variance Account.

| USofA # | Account Description |
|---|---|
| CR/DR 6035 | Other Interest Expense |
| DR/CR 2405 | Other Regulatory Liabilities, Sub-Account "Distribution System Energy Storage – Grid Scale Variance Account" |

To record interest improvement on the principal balance of the Distribution System Energy Storage – Grid Scale Variance Account.

# HYDRO ONE DISTRIBUTION ACCOUNTING ORDER
# ACCOUNT 2405 – OTHER REGULATORY LIABILITIES, SUB-ACCOUNT DISTRIBUTION SYSTEM ENERGY STORAGE – RESIDENTIAL DEFERRAL ACCOUNT

Hydro One Distribution proposes the establishment of a new Account 2405 – Other Regulatory Liabilities, Sub-Account "Distribution System Energy Storage – Residential Deferral Account" to record the net revenue to Hydro One Distribution where a third-party is contracted to aggregate Hydro One owned residential battery storage units in D-SS-04 for the purposes of participating in the IESO markets, and generates net revenues to the benefit of Hydro One Distribution. Net revenues shall be recorded in this account in a manner consistent with the outcome of the Ontario Energy Board's consultation on the Framework for Energy Innovation.

The account will be established as Account 2405 – Other Regulatory Liabilities, Sub-Account "Distribution System Energy Storage – Residential Deferral Account" effective January 1, 2023. Hydro One Distribution will record interest on the balance in the sub-account using the interest rates set by the OEB. Simple interest will be calculated on the opening monthly balance of the account until the balance is fully disposed.

The following outlines the proposed accounting entries for this deferral account.

| USofA # | Account Description |
|---|---|
| DR 4325 | Revenues from Merchandise |
| CR 2405 | Other Regulatory Liabilities, Sub-Account "Distribution System Energy Storage – Residential Deferral Account" |

Initial entry to record into the Distribution System Energy Storage – Residential Deferral Account.

| USofA # | Account Description |
|---|---|
| DR 6035 | Other Interest Expense |
| CR 2405 | Other Regulatory Liabilities, Sub-Account "Distribution System Energy Storage – Residential Deferral Account" |

To record interest improvement on the principal balance of the Distribution System Energy Storage – Residential Deferral Account.

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# HYDRO ONE DISTRIBUTION ACCOUNTING ORDER
# ACCOUNT 1522 – PENSION/OPEB FORECAST ACCRUAL VERSUS ACTUAL CASH PAYMENT DIFFERENTIAL

Hydro One Distribution proposes the establishment of a modified Account 1522 – OPEB Forecast Accrual versus Actual Cash Payment Differential Account to track the differences between the forecast accrual amounts recovered in rates and the actual cash payments made for OPEBs. Hydro One Distribution's Account 1522 applies a modified approach from the OEB's Report on the Regulatory Treatment of Pension and OPEB Costs (EB-2015-0040) such that actual OPEB amounts recovered in rates includes both OM&A as well as capitalized OPEB amounts reflected in the form of total estimated depreciation expense.[1] All other aspects of Account 1522 remain consistent with the OEB's Report on the Regulatory Treatment of Pension and OPEB Costs. This account shall have three sub-accounts:

1. Pension/OPEB Forecast Accrual versus Actual Cash Payment Differential
2. Pension/OPEB Forecast Accrual versus Actual Cash Payment Differential Contra Account
3. OPEB Asymmetrical Carrying Charge Variance Account

The modified account will be established as Account 1522 – OPEB Forecast Accrual versus Actual Cash Payment Differential Account effective January 1, 2018. Hydro One Distribution will record the carrying charges interest on the primary sub-account using the interest rates set by the OEB. Simple interest will be calculated on the opening monthly balance of the primary sub-account until the balance is fully disposed. The interest rate shall be the CWIP rate prescribed by the OEB.

The following outlines the proposed accounting entries for this variance account.

| USofA # | Account Description |
|---|---|
| DR 1522 | OPEB Forecast Accrual versus Actual Cash Payment Differential Account |
| CR 1522 | OPEB Forecast Accrual versus Actual Cash Payment Differential Contra Account |

To track the difference between the total OPEB accrual amount approved in rates and the actual cash amount paid.

[1] Refer to Exhibit G-01-02, Sections 7.6 and 7.7 for further details

| USofA # | Account Description |
|---|---|
| DR 6035 | Other Interest Expense |
| CR 1522 | OPEB Asymmetrical Carrying Charge Variance Account |

To record the carrying charge on the OPEB Forecast Accrual versus Actual Cash Payment Differential sub-account.