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

# DECISION AND RATE ORDER

# EB-2025-0051

# BURLINGTON HYDRO INC.

**Application for electricity distribution rates and other charges beginning January 1, 2026**

**BEFORE:** **Allison Duff**
Presiding Commissioner

**Damien A. Côté**
Commissioner

**Vinay Sharma**
Commissioner

**November 25, 2025**

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# 1 OVERVIEW

The Ontario Energy Board (OEB) accepts the settlement proposal (Settlement Proposal), as filed by Burlington Hydro Inc. (Burlington Hydro) on September 19, 2025. The OEB approves the updated Tariff of Rates and Charges filed by Burlington Hydro on November 24, 2025, which updated Appendix B of the Settlement Proposal for the OEB's published 2026 cost of capital parameters.

As a result of this Decision and Rate Order, it is estimated that a typical residential customer with a monthly consumption of 750 kWh could see a total bill increase (excluding taxes and the Ontario Electricity Rebate) of approximately $3.93 per month (2.95%).

This Decision enables new investments by Burlington Hydro of $21.6M to support the reliability and quality of service for Burlington Hydro's customers for the next five years. It also reflects a reduction in the capital and operating budgets of $3.25M (-13%) and $4.2M (-14%) respectively, relative to Burlington Hydro's application. The OEB accepts that with these lower budgets, Burlington Hydro will still deliver customer services and upkeep the distribution system in accordance with good utility practice, as indicated in the settlement.

Burlington Hydro's application sought approval for changes to the rates it charges for electricity distribution effective January 1, 2026. Burlington Hydro and the parties listed below reached a complete settlement on all issues included on the approved Issues List:

- Coalition of Concerned Manufacturers and Businesses of Canada (CCMBC)
- Consumers Council of Canada (CCC)
- Distributed Resource Coalition (DRC)
- Environmental Defence (ED)
- Pollution Probe (PP)
- School Energy Coalition (SEC)
- Vulnerable Energy Consumers Coalition (VECC)

OEB staff filed a letter supporting the Settlement Proposal on September 26, 2025. In its submission, OEB staff submitted that the Settlement Proposal was in the public interest and would result in just and reasonable rates for customers of Burlington Hydro.

# 2 CONTEXT AND PROCESS

The OEB's *Renewed Regulatory Framework for Electricity*[1] and *Handbook for Utility Rate Applications*[2] provide distributors with performance-based rate application options that support the cost-effective planning and efficient operation of a distribution network. This framework provides an appropriate alignment between a sustainable, financially viable electricity sector and the expectations of customers for reliable service at a reasonable price.

On April 16, 2025, Burlington Hydro filed a cost of service application with the OEB under section 78 of the *Ontario Energy Board Act, 1998*. The application requested OEB approval of Burlington Hydro's proposed electricity distribution rates for five years, using the Price Cap Incentive Rate-setting (Price Cap IR) option described in the *Renewed Regulatory Framework for Electricity*. Under the Price Cap IR option, with an approved 2025 Test Year, Burlington Hydro is eligible to apply to have its 2027-2030 rates adjusted mechanistically, based on inflation and the OEB's assessment of Burlington Hydro's efficiency.

The application was accepted as complete by the OEB on April 30, 2025. The OEB issued a Notice of Hearing on May 8, 2025, inviting parties to apply for intervenor status.

CCMBC, CCC, DRC, Enbridge Gas Inc., Environmental Defence, Pollution Probe, SEC, and VECC applied for intervenor status. All except Enbridge Gas also applied for, and were granted, cost eligibility. Enbridge Gas Inc. was an intervenor but did not participate in the settlement conference and is not a party to the Settlement Proposal. OEB staff attended the settlement conference; however, it is not a party to the Settlement Proposal.

The OEB issued Procedural Order No. 1 on June 4, 2025 which established, among other things, the timetable for an interrogatory process[3] and a settlement conference.

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[1] *Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach*, October 18, 2012.
[2] *Handbook for Utility Rate Applications*, October 13, 2016.
[3] As part of its efforts under the OEB's modernization plan, the OEB piloted new methods to reduce duplication and improve efficiency in the interrogatory process. This proceeding was selected to pilot item #4 of the OEB's 10-point Action Plan. Intervenors were directed to collaborate and file a single, consolidated set of interrogatories on behalf of all intervenors

A settlement conference was held on August 11-14, 2025. Burlington Hydro, intervenors, and OEB staff participated in the settlement conference.

Burlington Hydro filed a Settlement Proposal covering all issues on September 19, 2025. The Settlement Proposal is attached as Schedule A to this Decision and Order. OEB staff submitted a submission supporting the OEB's approval of the Settlement Proposal on September 26, 2025.

On November 24, 2025, Burlington Hydro updated its 2026 cost of capital parameters to incorporate those published by the OEB on October 31, 2025, as anticipated in the Settlement Proposal. Burlington Hydro also filed an updated Tariff of Rates and Charges reflecting these updated cost of capital parameters, and a bill impact model for the OEB's consideration.

# 3 DECISION ON THE SETTLEMENT PROPOSAL

The Settlement Proposal addressed all issues on the OEB's approved Issues List for this proceeding and therefore represents a full settlement.

The following are some of the key aspects of the Settlement Proposal.

- Revenue Requirement: Reduced by approximately $5.13 million, from $48.59M to $43.46M.
- Rate Base: Reduced by $4.8 million, from $184.0M to $179.2M.
- Operations, Maintenance, and Administration (OM&A): Reduced by $4.2 million, from $30.16M to $25.96M.
- Capital Expenditures: Reduced by $3.25 million, from $24.9M to $21.6M, with a new System Access Variance Account established to track deviations from forecast.
- Depreciation Adjustments: Adjusted accumulated depreciation for GIS and CIS assets to reflect a 5-year useful life (20% rate) thereby extending the OEB's approvals in Burlington Hydro's 2021 cost of service proceeding beyond 2025.
- Load Forecast: Updated to reflect COVID impacts and customer changes.
- Rate mitigation via a two-year disposition of Group 1 and 2 Deferral and Variance Account balances totaling $5.92M.
- Group 2 Deferral and Variance Accounts: Discontinuation of 14 legacy accounts listed in Table 6.1B of the Settlement Proposal.
- Advanced Capital Module: Approved for SCADA/ADMS replacement, with in-service date deferred from 2027 to 2028.

### Findings

The OEB accepts the Settlement Proposal to establish Burlington Hydro's distribution rates for five years. The Settlement Proposal provides for new rates effective January 1, 2026, with the ability to apply to have its 2027-2030 rates adjusted based on a settled adjustment formula, under the OEB's Price Cap IR option.

The OEB finds that the Settlement Proposal results in just and reasonable rates and to be in the public interest, as it strikes a balance between the needs of Burlington Hydro's customers and its shareholders. In particular, the OEB notes the asymmetrical System Access Variance account to record the revenue requirement difference between forecast and actual capital additions net of capital contributions. This asymmetrical variance account appears to address the risk and uncertainties associated with five-year forecasts in Burlington Hydro's service area given the current business environment.

In addition, the OEB accepts the following commitments made by Burlington Hydro in Appendix A of the Settlement Proposal:

- Continue to track the two new reliability metrics and three new unit cost metrics agreed to as part of Settlement Proposal in EB-2020-0007.
- Continue to track proactive versus reactive asset replacement (quantity and total expenditures for both reactive and proactive replacements) agreed to as part of Settlement Proposal in EB-2020-0007.
- Undertake all reasonable efforts to collaborate with IESO, City of Burlington, and other relevant stakeholders to support eDSM program delivery within service territory, and report on efforts at next rebasing.
- Consider system demand and capacity to ensure the system can meet future customer and energy transition needs, including DERs, and this work will be considered in development of Burlington Hydro's next DSP.
- Carry out work and activities related to grid modernization, electric vehicles, and cost-effective distribution loss reductions, as described in Appendix A of Settlement Proposal.
- Conduct a further study during the next rate period to build on learnings from June 21, 2023 report, as described in Appendix A of Settlement Proposal.
- Endeavour to reduce DER connection costs, including but not limited to connection impact assessment costs, as described in Appendix A of Settlement Proposal.

The OEB considered the two draft accounting orders in Appendix C of the Settlement Proposal to establish the following two new deferral and variance accounts:

- System Access Variance Account (Account 1508 sub-account)
- Cloud Computing Implementation Costs – Enterprise Resource Planning Replacement Account (Account 1508).

The OEB approves both of these draft accounting orders as the drafts are consistent with Section 6.1 of the approved Settlement Proposal.

# 4 DECISION ON THE CONFIDENTIALITY REQUEST

Burlington Hydro requested confidential treatment of certain information filed in Appendix D of the Settlement Proposal filed on September 19, 2025.

The information was filed in Burlington Hydro's response to pre-settlement clarification question Staff-103(a) Table 1. In accordance with the OEB's *Practice Direction on Confidential Filings*[4], Burlington Hydro filed a redacted version of the response for the public record, and an unredacted version for the OEB's consideration.

Burlington Hydro asserted that disclosure of the redacted information identifies security vulnerabilities with respect to Burlington Hydro's infrastructure and could adversely impact the safety and security of the distribution system, including related assets and facilities.

No objection to the confidentiality request was filed by either OEB staff or intervenors.

### Findings

The OEB approves the confidentiality request as filed. The OEB finds that the redacted information should be treated confidentially as it includes technical information that could be exploited by malicious actors if placed on the public record. Specifically, in accordance with Appendix A of the *Practice Direction on Confidential Filings*, the OEB finds that disclosure could potentially harm Burlington Hydro and risk public security.

[4] OEB's Practice Direction on Confidential Filings, Section 5.1, October 17, 2021.

# 5 IMPLEMENTATION

The approved effective date for Burlington Hydro's new rates is January 1, 2026, as proposed by the Parties.

Burlington Hydro filed tariff sheets and detailed supporting material with the Settlement Proposal, including all relevant calculations showing the impact of the implementation of the Settlement Proposal on its revenue requirement, the allocation of the revenue requirement to its rate classes and the determination of the rates and rate riders, including bill impacts. On November 24, 2025, Burlington Hydro filed an updated tariff sheet and bill impact model incorporating the OEB’s published 2026 cost of capital parameters, as anticipated in the Settlement Proposal.

The OEB made some changes to the wording and formatting of the updated Tariff of Rates and Charges to ensure consistency with the tariff sheets of other Ontario electricity distributors. The final approved Tariff of Rates and Charges is attached as Schedule A to this Decision and Rate Order.

The OEB has made provision in the Order section for eligible intervenors to file their cost claims. The OEB will issue its cost awards decision after the steps outlined in the following Order section are completed.

# 6 ORDER

**THE ONTARIO ENERGY BOARD ORDERS THAT:**

1. The Tariff of Rates and Charges set out in Schedule A of this Decision and Rate Order is approved as final, effective January 1, 2026. The Tariff of Rates and Charges will apply to electricity consumed, or estimated to have been consumed, on and after January 1, 2026. Burlington Hydro shall notify its customers of the rate changes no later than the delivery of the first bill, reflecting the new final rates.

2. The Settlement Proposal set out in Schedule B of this Decision and Rate Order is accepted.

3. The Accounting Orders as set in Schedule C of this Decision and Rate Order are approved to establish two new deferral and variance accounts.

**THE ONTARIO ENERGY BOARD FURTHER ORDERS THAT:**

4. Cost-eligible intervenors shall submit cost claims to the OEB and forward a copy to Burlington Hydro Inc. by **December 9, 2025**.

5. Burlington Hydro Inc. shall file with the OEB and forward to all parties any objections to the claimed costs by **December 15, 2025**.

6. Intervenors shall file with the OEB and forward to Burlington Hydro Inc. any responses to any objections for cost claims by **December 19, 2025**.

7. Burlington Hydro Inc. shall pay the OEB's costs incidental to this proceeding upon receipt of the OEB's invoice.

8. Burlington Hydro shall fulfill or cause to be fulfilled all of the commitments it made and which are listed on the Commitment List:

    - Burlington Hydro will continue to track the two new reliability metrics and three new unit cost metrics agreed to as part of the Settlement Proposal in EB-2020-0007.

    - Burlington Hydro will continue to track proactive versus reactive asset replacement (quantity and total expenditures for both reactive and proactive replacements) agreed to as part of the Settlement Proposal in EB-2020-0007.

- Burlington Hydro will undertake all reasonable efforts to collaborate with the IESO, the City of Burlington, and other relevant stakeholders to support eDSM program delivery within its service territory, and will report on its efforts at its next rebasing.

- Burlington Hydro will consider system demand and capacity to ensure its system can meet future customer and energy transition needs, including DERs, and this work will be considered in the development of Burlington Hydro's next DSP. Burlington Hydro shall carry out the work and activities related to grid modernization, electric vehicles, and cost-effective distribution loss reductions, as described in Appendix A of the Settlement Proposal.

- Burlington Hydro shall conduct a further study during the next rate period to build on the learnings from its June 21, 2023 report, as described in Appendix A of the Settlement Proposal.

- Burlington Hydro shall endeavor to reduce DER connection costs, including but not limited to connection impact assessment costs, as described in Appendix A of the Settlement Proposal.

Please quote file number, **EB-2025-0051** for all materials filed and submit them in searchable/unrestricted PDF format with a digital signature through the OEB's online filing portal.

- Filings should clearly state the sender's name, postal address, telephone number and e-mail address.
- Please use the document naming conventions and document submission standards outlined in the Regulatory Electronic Submission System (RESS) Document Guidelines found at the File documents online page on the OEB's website.
- Parties are encouraged to use RESS. Those who have not yet set up an account, or require assistance using the online filing portal can contact registrar@oeb.ca for assistance.
- Cost claims are filed through the OEB's online filing portal. Please visit the File documents online page of the OEB's website for more information. All participants shall download a copy of their submitted cost claim and serve it on all required parties as per the Practice Direction on Cost Awards.

All communications should be directed to the attention of the Registrar and be received by end of business, 4:45 p.m., on the required date.

With respect to distribution lists for all electronic correspondence and materials related to this proceeding, parties must include the Case Manager, Petar Prazic at Petar.Prazic@oeb.ca and OEB Counsel, Michael Millar at Michael.Millar@oeb.ca.

**DATED** at Toronto November 25, 2025

**ONTARIO ENERGY BOARD**

Ritchie Murray

Digitally signed by Ritchie Murray
Date: 2025.11.25 15:33:16 -05'00'

Ritchie Murray
Acting Registrar

**SCHEDULE A**

**TARIFF OF RATES AND CHARGES**

**BURLINGTON HYDRO INC.**

**EB-2025-0051**

**NOVEMBER 25, 2025**

# Burlington Hydro Inc.

## TARIFF OF RATES AND CHARGES

### Effective and Implementation Date January 1, 2026

**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2025-0051**

## RESIDENTIAL SERVICE CLASSIFICATION

This classification applies to low voltage connection assets that operate at 750 volts or less and supply electrical energy to residential customers where such energy is used exclusively in separately 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 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 | $ | 36.74 |
| Rate Rider for Disposition of Account 1509 - effective until December 31, 2027 | $ | 0.05 |
| Rate Rider for Group 2 Deferral/Variance Account Balances - effective until December 31, 2027 | $ | 0.50 |
| Smart Metering Entity Charge - effective until December 31, 2027 | $ | 0.42 |
| Rate Rider for Disposition of Deferral/Variance Accounts - effective until December 31, 2027 | $/kWh | 0.0001 |
| Rate Rider for Disposition of Capacity Based Recovery (CBR) Account Applicable only for Class B Customers - effective until December 31, 2027 | $/kWh | 0.0003 |
| Rate Rider for Disposition of Global Adjustment Account - Applicable to Non-RPP Customers Only - effective until December 31, 2027 | $/kWh | 0.0030 |
| Retail Transmission Rate - Network Service Rate | $/kWh | 0.0124 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kWh | 0.0092 |

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR | $/kWh | 0.0041 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0015 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Burlington Hydro Inc.

## TARIFF OF RATES AND CHARGES

### Effective and Implementation Date January 1, 2026

**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2025-0051**

## GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION

This classification applies to low voltage connection assets that operate at 750 volts or less and supply electricity to general service customers whose monthly average peak demand during a calendar year is less than, or forecast by BHI 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 | $ | 28.87 |
| Rate Rider for Disposition of Account 1509 - effective until December 31, 2027 | $ | 0.11 |
| Smart Metering Entity Charge - effective until December 31, 2027 | $ | 0.42 |
| Distribution Volumetric Rate | $/kWh | 0.0222 |
| Rate Rider for Disposition of Deferral/Variance Accounts - effective until December 31, 2027 | $/kWh | 0.0001 |
| Rate Rider for Disposition of Capacity Based Recovery (CBR) Account Applicable only for Class B Customers - effective until December 31, 2027 | $/kWh | 0.0003 |
| Rate Rider for Disposition of Global Adjustment Account - Applicable to Non-RPP Customers Only - effective until December 31, 2027 | $/kWh | 0.0030 |
| Rate Rider for Group 2 Deferral/Variance Account Balances - effective until December 31, 2027 | $/kWh | 0.0006 |
| Retail Transmission Rate - Network Service Rate | $/kWh | 0.0119 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kWh | 0.0084 |

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR | $/kWh | 0.0041 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0015 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Burlington Hydro Inc.

## TARIFF OF RATES AND CHARGES

### Effective and Implementation Date January 1, 2026

**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2025-0051**

## GENERAL SERVICE 50 TO 4,999 KW SERVICE CLASSIFICATION

This classification applies to general service customers with a monthly average peak demand during a calendar year equal to or greater than, or is forecast by Burlington Hydro Inc. 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.

# Burlington Hydro Inc.
## TARIFF OF RATES AND CHARGES
### Effective and Implementation Date January 1, 2026
**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2025-0051**

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 73.36 |
| Rate Rider for Disposition of Account 1509 - effective until December 31, 2027 | $ | 1.15 |
| Distribution Volumetric Rate | $/kW | 4.5127 |
| Rate Rider for Disposition of Deferral/Variance Accounts - effective until December 31, 2027 | $/kW | 0.0407 |
| Rate Rider for Disposition of Capacity Based Recovery (CBR) Account Applicable only for Class B Customers - effective until December 31, 2027 | $/kW | 0.0890 |
| Rate Rider for Disposition of Global Adjustment Account - Applicable to Non-RPP Customers Only - effective until December 31, 2027 | $/kWh | 0.0030 |
| Rate Rider for Group 2 Deferral/Variance Account Balances - effective until December 31, 2027 | $/kW | 0.2118 |
| Retail Transmission Rate - Network Service Rate - Interval Metered | $/kW | 4.9016 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate - Interval Metered | $/kW | 3.6523 |

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR | $/kWh | 0.0041 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0015 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Burlington Hydro Inc.

## TARIFF OF RATES AND CHARGES

### Effective and Implementation Date January 1, 2026

**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2025-0051**

## UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

This classification applies to low voltage connection assets that operate at 750 volts or less and supply electricity to general service customers whose monthly average peak demand during a calendar year is less than, or forecast by Burlington Hydro Inc. 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 customer will provide detailed manufacturer information/documentation with regard to electrical demand/consumption of the proposed unmetered load. 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 | $ | 10.87 |
| Rate Rider for Disposition of Account 1509 - effective until December 31, 2027 | $ | 0.03 |
| Distribution Volumetric Rate | $/kWh | 0.0189 |
| Rate Rider for Disposition of Deferral/Variance Accounts - effective until December 31, 2027 | $/kWh | 0.0001 |
| Rate Rider for Disposition of Capacity Based Recovery (CBR) Account Applicable only for Class B Customers - effective until December 31, 2027 | $/kWh | 0.0003 |
| Rate Rider for Group 2 Deferral/Variance Account Balances - effective until December 31, 2027 | $/kWh | 0.0007 |
| Retail Transmission Rate - Network Service Rate | $/kWh | 0.0119 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kWh | 0.0084 |

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR | $/kWh | 0.0041 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0015 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Burlington Hydro Inc.

## TARIFF OF RATES AND CHARGES

### Effective and Implementation Date January 1, 2026

**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2025-0051**

## STREET LIGHTING SERVICE CLASSIFICATION

This classification refers to roadway lighting customers such as the City of Burlington, the Regional Municipality of Halton, Ministry of Transportation and private roadway lighting, controlled by photo cells. The daily consumption for these customers will be based on the calculated connected load times the required night time or 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 device) | $ | 0.71 |
| Rate Rider for Disposition of Account 1509 - effective until December 31, 2027 | $ | 0.00 |
| Distribution Volumetric Rate | $/kW | 5.0622 |
| Rate Rider for Disposition of Deferral/Variance Accounts - effective until December 31, 2027 | $/kW | 0.0392 |
| Rate Rider for Disposition of Capacity Based Recovery (CBR) Account Applicable only for Class B Customers - effective until December 31, 2027 | $/kW | 0.0903 |
| Rate Rider for Disposition of Global Adjustment Account - Applicable to Non-RPP Customers Only - effective until December 31, 2027 | $/kWh | 0.0030 |
| Rate Rider for Group 2 Deferral/Variance Account Balances - effective until December 31, 2027 | $/kW | 0.2355 |
| Retail Transmission Rate - Network Service Rate | $/kW | 3.5821 |
| Retail Transmission Rate - Line Connection Service Rate | $/kW | 2.5991 |

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR | $/kWh | 0.0041 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0015 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Burlington Hydro Inc.
## TARIFF OF RATES AND CHARGES
### Effective and Implementation Date January 1, 2026
**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2025-0051**

## 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 | $ | 5.00 |

# Burlington Hydro Inc.

## TARIFF OF RATES AND CHARGES

### Effective and Implementation Date January 1, 2026

**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2025-0051**

## 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

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 |
| Credit reference/credit check (plus credit agency costs) | $ | 15.00 |
| Statement of account | $ | 15.00 |
| Account set up charge/change of occupancy charge (plus credit agency costs if applicable) | $ | 30.00 |
| Returned cheque (plus bank charges) | $ | 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

| | | |
|---|---|---|
| Temporary service - install & remove - overhead - no transformer | $ | 500.00 |
| Specific charge for wireline access to the power poles - $/pole/year (with the exception of wireless attachments) | $ | 40.59 |

## RETAIL SERVICE CHARGES (if applicable)

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.

# Burlington Hydro Inc.
## TARIFF OF RATES AND CHARGES
### Effective and Implementation Date January 1, 2026
**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2025-0051**

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 | $ | 125.72 |
| Monthly Fixed Charge, per retailer | $ | 50.29 |
| Monthly Variable Charge, per customer, per retailer | $/cust. | 1.24 |
| Distributor-consolidated billing monthly charge, per customer, per retailer | $/cust. | 0.74 |
| Retailer-consolidated billing monthly credit, per customer, per retailer | $/cust. | (0.74) |
| Service Transaction Requests (STR) | | |
| Request fee, per request, applied to the requesting party | $ | 0.63 |
| Processing fee, per request, applied to the requesting party | $ | 1.24 |
| 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) | $ | 5.03 |
| 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) | $ | 2.51 |

## 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 | 1.0422 |
| Total Loss Factor - Primary Metered Customer < 5,000 kW | 1.0319 |

# SCHEDULE B

# SETTLEMENT PROPOSAL

# BURLINGTON HYDRO INC.

# EB-2025-0051

# NOVEMBER 25, 2025

Burlingtonhydro inc.

Registrar
Ontario Energy Board
27th Floor
2300 Yonge Street
Toronto, ON
M4P 1E4

September 19, 2025

Dear Mr. Murray,

**Re: OEB File No. EB-2025-0051, Burlington Hydro Inc. ("BHI")**
**2026 Cost of Service Application for Electricity Distribution Rates**
**Settlement Proposal**

Please find attached BHI's Settlement Proposal for its 2026 Cost of Service Application EB-2025-0051, pursuant to Procedural Order No. 2.

A Settlement Conference was held from August 11 to 14, 2025 in which BHI and the following 7 intervenors participated:

- Coalition of Concerned Manufacturers and Businesses of Canada (CCMBC)
- Consumers Council of Canada (CCC)
- Distributed Resource Coalition (DRC)
- Environmental Defence (ED)
- Pollution Probe (PP)
- School Energy Coalition (SEC)
- Vulnerable Energy Consumers Coalition (VECC)

The filed documents include:

- Settlement Proposal, which includes:
  - Appendix A: Settlement Commitments
  - Appendix B: Proposed Tariff of Rates and Charges
  - Appendix C: Accounting Orders
  - Appendix D: Responses to Pre-Settlement Conference Clarification Questions
- Live Excel models in support of the Settlement Proposal

Respectfully submitted,

Adam Pappas
Director, Regulatory Affairs, Supply Chain and Capital Planning
Email: apappas@burlingtonhydro.com
Tel: 905-332-2341

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

**AND IN THE MATTER OF** an application by Burlington Hydro Inc. for an order approving just and reasonable rates and other charges for electricity distribution beginning January 1, 2026.

**BURLINGTON HYDRO INC.**

**SETTLEMENT PROPOSAL**

**September 19, 2025**

**Burlington Hydro Inc.**
**EB-2025-0051**
**Settlement Proposal**

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## APPENDICES

**Appendix A:** Settlement Commitments
**Appendix B:** Proposed Tariff of Rates and Charges
**Appendix C:** Accounting Orders
**Appendix D:** Pre-Settlement Conference Clarification Questions

## LIVE EXCEL MODELS

In addition to the Appendices listed above, the following live Excel models have been filed together with and form an integral part of this Settlement Proposal:

Settlement_Attachment_OEB_Chapter2Appendices_BHI
Settlement_Attachment_Load_Forecast_Model_BHI
Settlement_Attachment_2025_RRWF_BHI
Settlement_Attachment_2026_PILS_Workform_BHI
Settlement_Attachment_DVA_Continuity_Schedule_BHI
Settlement_Attachment_2026_Cost Allocation Model_v1.0_BHI
Settlement_Attachment_2026_RTSR_Workform_BHI
Settlement_Attachment_Tariff_Schedule_and_Bill_Impact_Model_BHI
Settlement_Attachment_Benchmarking_Spreadsheet_Forecast_Model_BHI
Settlement_Attachment_2026_ACM_ICM_Model_BHI

**Burlington Hydro Inc.**
**EB-2025-0051**
**Settlement Proposal**

**Filed with OEB:** September 19, 2025

Burlington Hydro Inc. (the "**Applicant**" or "**BHI**") filed a Cost of Service application with the Ontario Energy Board (the "**OEB**") on April 16, 2025 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 BHI charges for electricity distribution and other charges, to be effective January 1, 2025 (OEB Docket Number EB-2025-0051) (the "**Application**").

The OEB issued and published a Notice of Hearing dated May 8, 2025, and Procedural Order No. 1 on June 4, 2025, the latter of which required the parties to the proceeding to develop a proposed Issues List by June 10, 2025 and scheduled a Settlement Conference for July 24, 25 and 28 2025.

On June 11, 2025, Ontario Energy Board staff ("**OEB Staff**") submitted a proposed Issues List as agreed to by the parties. On June 19, 2025, the OEB issued its Decision on the proposed Issues List and Procedural Order No. 2, approving the list submitted by OEB Staff (the "**Issues List**") with the exception of two minor changes to wording of the proposed issues. And amended the schedule of the proceeding, which, among other things, changed the date of the Settlement Conference to August 11, 12, and 13, 2025.

BHI filed its Interrogatory Responses with the OEB on July 24, 2025, pursuant to which BHI updated several models and submitted them to the OEB as Excel documents.

A Settlement Conference was convened on August 11, 2025 and continued to August 14, 2025, in accordance with the OEB's *Rules of Practice and Procedure* and the OEB's *Practice Direction on Settlement Conferences* (the "**Practice Direction**"), which extended for an additional day beyond the timeline contemplated in Procedural Order No. 2.

Karen Wianecki acted as facilitator for the Settlement Conference which lasted for four days.

BHI and the following Intervenors, participated in the settlement conference:

- Coalition of Concerned Manufacturers and Businesses of Canada ("**CCMBC**")
- Consumers Council of Canada ("**CCC**")
- Distributed Resource Coalition ("**DRC**")
- Environmental Defence Canada Inc. ("**ED**")
- Pollution Probe ("**PP**")
- School Energy Coalition ("**SEC**")
- Vulnerable Energy Consumers Coalition ("**VECC**")

The above Intervenors and Enbridge Gas Inc. ("**Enbridge**") are collectively referred to as the "**Intervenors**". BHI and the Intervenors, with the exception of Enbridge, are collectively referred to below as the "**Parties**". Notwithstanding any other clause of this Settlement Proposal, Enbridge did not attend the Settlement Conference and was not a party to this Settlement, and takes no position with respect to, and does not oppose, any of the issues set out in the Issues List.

OEB Staff also participated in the Settlement Conference. The role adopted by OEB Staff is set out in page 5 of the Practice Direction. Although OEB Staff is not a party to this Settlement Proposal, as noted in the Practice Direction, OEB Staff who did participate in the Settlement Conference are bound by the same confidentiality requirements that apply to the Parties to the proceeding.

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. 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 this settlement proceeding is confidential and privileged 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, and the rules of that latter document do not apply. Instead, in this 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 proceeding, the discussion of each issue, the offers and counter-offers, and the negotiations leading to the settlement – or not – of each issue during the settlement conference are strictly privileged and without prejudice. None of the foregoing is admissible as evidence in this proceeding, or otherwise, with one exception, being 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 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 engage to assist them with the settlement conference, and (b) any persons or entities from whom they seek 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.

This Settlement Proposal provides a brief description of each of the settled issues, together with references to the evidence. The Parties agree that references to the "evidence" in this Settlement

Proposal shall, unless the context otherwise requires, include (a) additional information included by the Parties in this Settlement Proposal, (b) the Appendices to this document, and (c) the evidence filed concurrently with this Settlement Proposal titled "Responses to Pre-settlement Clarification Questions" ("**Clarification Questions**"). 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 to this Settlement Proposal which provide further support for the proposed settlement. The Parties acknowledge that the Appendices were prepared by BHI. While the Intervenors have reviewed the Appendices, the Intervenors are relying on the accuracy of those Appendices and the underlying evidence in entering into this Settlement Proposal.

Outlined below are the final positions of the Parties following the settlement conference. For ease of reference, this Settlement Proposal follows the format of the final approved issues list for the Application attached to the Issues List Decision and Procedural Order No. 2 dated June 19, 2025.

The Parties are pleased to advise the OEB that they have reached a complete agreement with respect to the settlement of all of the issues in this proceeding. Specifically:

| | |
|---|---|
| "**Complete Settlement**" means an issue for which complete settlement was reached by all Parties, and if this Settlement Proposal is accepted by the OEB, the Parties will not adduce any evidence or argument during the oral hearing in respect of these issues. | # issues settled: # **All** |
| "**Partial Settlement**" means an issue for which there is partial settlement, as BHI 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 who take any position on the issue will only adduce evidence and argument during the hearing on those portions of the issues not addressed in this Settlement Proposal. | # issues partially settled: # **None** |
| "**No Settlement**" means an issue for which no settlement was reached. BHI and the Intervenors who take a position on the issue will adduce evidence and/or argument at the hearing on the issue. | # issues not settled: **None** |

According to the Practice Direction (p. 3), the Parties must consider whether a Settlement Proposal should include an appropriate adjustment mechanism for any settled issue that may be affected by external factors. These adjustments are specifically set out in the text of the Settlement Proposal.

The Parties have settled the issues as a package, and none of the parts of this Settlement Proposal are severable. If the OEB does not accept this Settlement Proposal in its entirety, then there is no settlement (unless the Parties agree in writing that any part(s) of this Settlement Proposal that the OEB does accept may continue as a valid settlement without inclusion of any part(s) that the OEB does not accept).

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 decide to take no position on the issue, prior to its resubmission to the OEB.

Unless stated otherwise, 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 Parties to raise the same issue and/or to take any position thereon in any other proceeding, whether or not BHI is a party to such proceeding.

Where in this Settlement Proposal, the Parties "accept" the evidence of BHI, or the Parties or any of them "agree" to a revised term or condition, including a revised budget or forecast, then unless the Settlement Proposal expressly states to the contrary, the words "for the purpose of settlement of the issues herein" shall be deemed to qualify that acceptance or agreement.

**Summary**

In reaching this complete settlement, the Parties have been guided by the current *Filing Requirements for Electricity Distribution Rate Applications* dated May 14, 2020, the *Handbook for Utility Rate Applications* dated October 13, 2016, the approved Issues List attached as to the OEB's Procedural Order No. 2 dated June 19, 2025, and the Report of the OEB titled *Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach* dated October 18, 2012.

This Settlement Proposal reflects a complete settlement of the issues in this proceeding.

Based on this Settlement Proposal, BHI has made changes to its 2026 Test year Revenue Requirement as identified in Table A below.

**Table A – Summary of Revenue Requirement**

| Category | Description | Application | Interrogatories | Variance | Settlement | Variance |
|---|---|---|---|---|---|---|
| | | a | b | c = b-a | d | e = d-b |
| Cost of Capital | Regulated Return on Capital | $11,445,947 | $11,401,653 | ($44,294) | $11,091,448 | ($310,205) |
| | Regulated Rate of Return | 6.20% | 6.20% | 0.00% | 6.19% | -0.01% |
| Rate Base and Capital Expenditure | Rate Base | $184,600,382 | $184,001,254 | ($599,127) | $179,198,840 | ($4,802,414) |
| | Net Fixed Assets | $168,957,808 | $168,444,817 | ($512,992) | $163,672,833 | ($4,771,984) |
| | Working Capital Base | $208,567,641 | $207,419,166 | ($1,148,475) | $207,013,436 | ($405,730) |
| | Working Capital Allowance | $15,642,573 | $15,556,437 | ($86,136) | $15,526,008 | ($30,430) |
| | 2026 Test Year Capital Expenditures | $24,271,845 | $24,870,805 | $598,960 | $21,620,805 | ($3,250,000) |
| Operating Expenses | Depreciation Expense | $10,046,886 | $10,065,714 | $18,828 | $9,652,371 | ($413,342) |
| | Taxes/PILs (Grossed up) | $931,830 | $925,602 | ($6,228) | $873,601 | ($52,001) |
| | OM&A (Excluding Property Taxes and Other Donations) | $30,040,101 | $30,157,314 | $117,213 | $25,957,314 | ($4,200,000) |
| | Property Taxes | $375,892 | $375,892 | $0 | $375,892 | $0 |
| Revenue Requirement | Service Revenue Requirement | $52,840,656 | $52,926,174 | $85,518 | $47,950,627 | ($4,975,547) |
| | Other Revenue | $4,355,525 | $4,339,019 | ($16,506) | $4,489,019 | $150,000 |
| | Base Revenue Requirement | $48,485,131 | $48,587,155 | $102,025 | $43,461,608 | ($5,125,547) |
| | Grossed Up Revenue Deficiency | $10,070,403 | $10,237,984 | $167,581 | $4,672,360 | ($5,565,624) |

The Bill impacts as a result of BHI's settlement proposal are identified in Table B below.

**Table B – Bill Impacts**

| Class | kWh | kW | Distribution (Fixed and Volumetric) | | | |
|---|---|---|---|---|---|---|
| | | | Current Rates | Proposed Rates | $ Change | % Impact |
| Residential | 750 | | $32.74 | $37.12 | $4.38 | 13.4% |
| GS<50 kW | 1500 | | $58.48 | $62.92 | $4.44 | 7.6% |
| GS<50 kW | 2000 | | $68.18 | $74.27 | $6.09 | 8.9% |
| GS>50 kW | 36700 | 200 | $851.96 | $1,014.96 | $163.00 | 19.1% |
| Street Lighting | 175 | 0.22 | $1.68 | $1.86 | $0.18 | 10.7% |
| Unmetered Scattered Load | 2000 | | $48.64 | $49.84 | $1.20 | 2.5% |
| | | | | | | |
| Class | kWh | kW | Total Bill (after HST and OER) | | | |
| | | | Current Rates | Proposed Rates | $ Change | % Impact |
| Residential | 750 | | $133.18 | $136.94 | $3.76 | 2.8% |
| GS<50 kW | 1500 | | $256.83 | $259.87 | $3.05 | 1.2% |
| GS<50 kW | 2000 | | $332.43 | $336.66 | $4.24 | 1.3% |
| GS>50 kW | 36700 | 200 | $7,871.45 | $8,011.30 | $139.85 | 1.8% |
| Street Lighting | 175 | 0.22 | $26.82 | $27.33 | $0.50 | 1.9% |
| Unmetered Scattered Load | 2000 | | $312.49 | $311.84 | ($0.65) | (0.2%) |

The impact of the Settlement Proposal on BHI's cost performance and Stretch Factor Cohort is identified in Table C below.

**Table C – Cost Benchmarking Results**

| Description | 2023 Actuals | 2024 Actuals | 2025 Bridge Year | 2026 Test Year |
|---|---|---|---|---|
| Actual Total Cost | $59,075,631 | $61,448,092 | $61,937,821 | $69,368,744 |
| Predicted Total Cost | $65,280,800 | $68,773,780 | $66,887,700 | $74,982,827 |
| Actual Cost Greater Than/(Less Than) Predicted Cost | ($6,205,170) | ($7,325,688) | ($4,949,879) | ($5,614,083) |
| **Percentage Difference (Cost Performance)** | **-10.0%** | **-11.3%** | **-7.7%** | **-7.8%** |
| Three-Year Average Performance | -11.7% | -11.6% | -9.6% | -8.9% |
| Stretch Factor Cohort - Annual | 3 | 2 | 3 | 3 |
| Stretch Factor Cohort - Annual (Three Year Average) | 2 | 2 | 3 | 3 |

Based on the foregoing and the evidence and rationale provided below, the Parties agree that this Settlement Proposal is appropriate and recommend its acceptance by the OEB. Please refer to Appendix B for the Proposed Tariff of Rates and Charges resulting from the acceptance of this Settlement Proposal.

## 1. Capital Spending and Rate Base

### 1.1 Are the proposed capital expenditures and in-service additions appropriate?

**Complete Settlement:**

2026 Net Capital Expenditures and In-Service Additions: For the purposes of settlement, the Parties agree to reduce BHI's 2026 net capital expenditures and in-service additions by $3.25M from $24,870,805 as filed in OEB Appendices 2-AA and 2-AB of its interrogatory responses, resulting in 2026 Test Year capital expenditures of $21,620,805. This reduction consists of the following amounts:

(i) $1.25M in respect of net capital expenditures and in-service additions other than those in the System Access investment category; and

(ii) $2.00M in respect of net capital expenditures and in-service additions for the System Access investment category, subject to the System Access Variance Account as set out below.

2026 System Access Variance Account: For the purpose of settlement, the Parties agree to establish an asymmetrical variance account ("System Access Variance Account") to record the revenue requirement associated with the difference between actual 2026 System Access capital additions and forecasted 2026 System Access capital additions in the Application, net of capital contributions. The baseline net capital additions used to determine any variance will be $13,500,384. The account will be asymmetrical, such that (i) the maximum amount of additional 2026 System Access net capital additions used to calculate the revenue requirement recorded in the account will be limited to $2M above the baseline, reflecting BHI's forecast budget in the application, while (ii) the revenue requirement impact of the aggregate amount of actual 2026 System Access net capital additions that are less than the baseline will be fully recorded in the account.

The Parties agree that BHI shall seek clearance of the System Access Variance Account as part of any Advanced Capital Module ("**ACM**") or Incremental Capital Module ("**ICM**") application that BHI may file during the IRM period, and if not, shall seek clearance at its next rebasing application. The Parties also agree that for the purposes of calculating any ACM or ICM materiality threshold for BHI during the IRM period, the 2026 rate base shall be deemed to include the $2M maximum variance agreed upon by the Parties for the purposes of the System Access Variance Account regardless of the actual 2026 system access in-service additions.

Table 1.1A summarizes the capital expenditures by category for the 2026-2030 Distribution System Plan ("**DSP**") period. Since only the 2026 Test Year expenditures are being sought for approval in this proceeding, the revised Forecast Period (2027-2030) expenditures included in Table 1.1A are being provided by the Applicant and are not meant to be construed as the Parties agreement that the amounts are appropriate.

**Table 1.1A – Summary of Capital Expenditures by Category**

| Category | Forecast Period (planned) | | | | |
|---|---|---|---|---|---|
| | 2026 | 2027 | 2028 | 2029 | 2030 |
| System Access | $35,239,277 | $25,372,372 | $21,772,371 | $23,697,266 | $21,530,486 |
| System Renewal | $5,232,491 | $5,251,889 | $5,357,937 | $5,463,984 | $5,579,411 |
| System Service | $408,000 | $520,000 | $106,100 | $216,400 | $110,400 |
| General Plant | $2,439,129 | $3,008,934 | $5,435,191 | $2,587,285 | $1,089,875 |
| **Total Expenditure** | **$43,318,898** | **$34,153,195** | **$32,671,599** | **$31,964,935** | **$28,310,172** |
| Capital Contributions | ($21,698,094) | ($10,980,362) | ($11,881,636) | ($11,536,163) | ($10,329,774) |
| **Net Capital Expenditures** | **$21,620,805** | **$23,172,833** | **$20,789,963** | **$20,428,772** | **$17,980,398** |
| System O&M | $11,333,633 | $0 | $0 | $0 | $0 |

Table 1.1B below identifies the changes in the 2026 Test Year gross and net capital expenditures from BHI’s original Application to the Settlement proposal.

**Table 1.1B – Capital Expenditures**

| Category | Application | Interrogatories | Variance | Settlement | Variance |
|---|---|---|---|---|---|
| | a | b | c = b-a | d | e = d-b |
| System Access | $35,694,524 | $37,239,278 | $1,544,754 | $35,239,277 | ($2,000,000) |
| System Renewal | $6,180,741 | $6,180,741 | $0 | $5,232,491 | ($948,250) |
| System Service | $510,000 | $510,000 | $0 | $408,000 | ($102,000) |
| General Plant | $2,594,880 | $2,638,880 | $44,000 | $2,439,129 | ($199,751) |
| **Total Expenditure** | **$44,980,145** | **$46,568,899** | **$1,588,754** | **$43,318,898** | **($3,250,000)** |
| Capital Contributions | ($20,708,300) | ($21,698,094) | ($989,794) | ($21,698,094) | $0 |
| **Net Capital Expenditures** | **$24,271,845** | **$24,870,805** | **$598,960** | **$21,620,805** | **($3,250,000)** |

The Parties agree that the revised Test Year capital expenditures and additions, in conjunction with the newly established System Access Variance Account identified above, are reasonable. The Parties confirm that this level of spending is sufficient to maintain a safe and reliable distribution system and facilitate access for new connections and service upgrades.

Appendix A, which forms a binding and integral part of this Settlement Proposal, contains commitments that are integral to this issue, including items nos. 1, 2, 4, 5 and 6.

**Evidence:**

*Application:*
Exhibit 1 Sections 1.2.4 C
Exhibit 2, inclusive of Appendix A (DSP)

*IRs:*
2-Staff-4, 2-Staff-5, 2-Staff-8, 2-Staff-9, 2-Staff-10, 2-Staff-12, 2-Staff-13, 2-Staff-14, 2-Staff-16, 2-Staff-17, 2-Staff-18, 2-Staff-20, 2-Staff-21, 2-Staff-22, 2-Staff-23, 2-Staff-24, 2-Staff-25, 4-Staff-55, 4-Staff-59, 1-Intervenor-1, 1-Intervenor-2, 1-Intervenor-3, 1-Intervenor-4, 1-Intervenor-5, 1-Intervenor-6, 1-Intervenor-7, 1-Intervenor-8, 1-Intervenor-9, 1-Intervenor-11, 2-Intervenor-13, 2-Intervenor-14, 2-Intervenor-15, 2-Intervenor-16, 2-Intervenor-17, 2-Intervenor-30, 2-Intervenor-31, 2-Intervenor-32, 2-Intervenor-33, 2-Intervenor-34, 2-Intervenor-35, 2-Intervenor-36, 2-Intervenor-37, 2-Intervenor-38, 2-Intervenor-39, 2-Intervenor-40, 2-Intervenor-41, 2-Intervenor-42, 2-Intervenor-43, 2-Intervenor-45, 2-Intervenor-46, 2-Intervenor-47, 2-Intervenor-48, 2-Intervenor-49, 2-Intervenor-51, 2-Intervenor-52, -Intervenor-53, 2-Intervenor-54, 2-Intervenor-55, 2-Intervenor-56, 2-Intervenor-57, 2-Intervenor-58, 2-Intervenor-59, 2-Intervenor-60, 2-Intervenor-61, 2-Intervenor-62, 2-Intervenor-63, 2-Intervenor-64, 2-Intervenor-65, , 2, 2-Intervenor-66, 2-Intervenor-67, 2-Intervenor-68, 2-Intervenor-69, 2-Intervenor-70, 2-Intervenor-71, 2-Intervenor-72, , 2-Intervenor-73, 2-Intervenor-73, 2-Intervenor-74, 2-Intervenor-75, 2-Intervenor-76, 2-Intervenor-77, 2-Intervenor-78, 2-Intervenor-79, 2-Intervenor-80

*Clarifying Question Responses:*
Staff-96, Staff-97, Staff-102, Staff-103, Staff-104, ED-CQ-1, ED-CQ-2, ED-CQ-3, ED-CQ-4, ED-CQ-5, ED-CQ-6, ED-CQ-7, SC-CCC-3, SC-CCC-4, SC-CCC-6, SC-CCC-7, SEC-CQ-3, VECC-CQ-11

*Appendices to this Settlement Proposal:*
Appendix C: Accounting Orders

*Settlement Models:*
Settlement_Attachment_OEB_Chapter2Appendices_BHI

**Supporting Parties:** All

**Parties Taking No Position:** None

### 1.2 Are the proposed rate base and depreciation amounts appropriate?

**Complete Settlement:**

Subject to the modifications set out in this Issue 1.2 the Parties agree that the proposed rate base and depreciation amounts are appropriate:

(a) Opening 2026 Rate Base: The Parties agree to reduce BHI's 2026 Test Year opening gross fixed assets by $2.00M from $363,271,627 as filed in OEB Appendix 2-BA of BHI's interrogatory responses to $361,271,627.

(b) 2026 Rate Base: The Parties agree to reduce BHI's 2026 Test Year net capital expenditures and in-service additions by $3.25M based on the reductions to capital expenditures discussed in Issue 1.1.

(c) Accumulated Depreciation: The Parties agree to increase the opening 2026 accumulated depreciation for USoA 1611 by $1,372,768. The depreciation expense underpinning 2021 rates assumed a 20% depreciation rate for GIS and CIS assets. BHI calculated depreciation expense on its GIS and CIS assets using a 10% depreciation rate between 2022 and 2025. The Parties agree to adjust accumulated depreciation as if BHI had continued to depreciate the CIS and GIS assets, as approved in BHI's 2021 Cost of Service, using a 20% depreciation rate between 2022 and 2025. Table 1.2A identifies the changes in GIS and CIS depreciation as compared to that which was filed in BHI's original Application.

**Table 1.2A – Adjustment to GIS and CIS Depreciation**

| Description | Application | | | Adjustment | | | Settlement Proposal | | |
|---|---|---|---|---|---|---|---|---|---|
| | CIS | GIS | Total | CIS | GIS | Total | CIS | GIS | Total |
| 2026 Opening Gross Assets | 3,726,335 | 1,582,415 | 5,308,750 | - | - | - | 3,726,335 | 1,582,415 | 5,308,750 |
| 2026 Opening Accum Deprn | 2,088,974 | 877,430 | 2,966,404 | 1,021,000 | 351,768 | 1,372,768 | 3,109,974 | 1,229,198 | 4,339,172 |
| **2026 Opening Net Book Value** | **1,637,361** | **704,985** | **2,342,346** | **(1,021,000)** | **(351,768)** | **(1,372,768)** | **616,361** | **353,217** | **969,578** |
| 2026 Depreciation on 2021 Additions | 297,458 | 129,269 | 426,727 | (210,386) | (72,487) | (282,873) | 87,072 | 56,782 | 143,854 |
| 2026 Depreciation on 2022-2025 Additions | 26,917 | 9,939 | 36,856 | - | - | - | 26,917 | 9,939 | 36,856 |
| **2026 Total Depreciation** | **324,375** | **139,208** | **463,583** | **(210,386)** | **(72,487)** | **(282,873)** | **113,989** | **66,721** | **180,710** |
| 2026 Closing Gross Assets | 3,726,335 | 1,582,415 | 5,308,750 | - | - | - | 3,726,335 | 1,582,415 | 5,308,750 |
| 2026 Closing Accum Deprn | 2,413,349 | 1,016,638 | 3,429,987 | 810,614 | 279,281 | 1,089,895 | 3,223,963 | 1,295,919 | 4,519,882 |
| **2026 Closing Net Book Value** | **1,312,986** | **565,777** | **1,878,763** | **(810,614)** | **(279,281)** | **(1,089,895)** | **502,372** | **286,496** | **788,868** |

**Table 1.2B – Rate Base**

| Description | Application | Interrogatories | Variance | Settlement | Variance |
|---|---|---|---|---|---|
| | a | b | c = b-a | d | e = d-b |
| Average Gross Fixed Assets | $378,590,894 | $378,111,298 | ($479,596) | $374,486,297 | ($3,625,000) |
| Average Accumulated Depreciation | $209,633,086 | $209,666,481 | $33,395 | $210,813,464 | $1,146,983 |
| **Average Net Book Value** | **$168,957,808** | **$168,444,817** | **($512,992)** | **$163,672,833** | **($4,771,983)** |
| Working Capital Base | $208,567,641 | $207,419,166 | ($1,148,475) | $207,013,436 | ($405,730) |
| Working Capital Allowance (%) | 7.50% | 7.50% | 0.00% | 7.50% | 0.00% |
| **Working Capital Allowance ($)** | **$15,642,573** | **$15,556,437** | **($86,136)** | **$15,526,008** | **($30,430)** |
| **Rate Base** | **$184,600,382** | **$184,001,254** | **($599,127)** | **$179,198,840** | **($4,802,413)** |

**Evidence:**

*Application:*
Exhibit 1 Sections 1.2.4 C
Exhibit 2, inclusive of Appendix A (DSP)

*IRs:*
2-Staff-3, 2-Staff-6, 2-Staff-7, 2-Staff-11, 2-Staff-15, 2-Staff-27, 2-Staff-28, 2-Staff-29, 2-Staff-30, 2-Intervenor-18, 2-Intervenor-19, 2-Intervenor-20, 2-Intervenor-21, 2-Intervenor-44, 2-Intervenor-50, 2-Intervenor-65, , 2-Intervenor-73

*Clarifying Question Responses:*
Staff-99, Staff-100, Staff-101, SC-CCC-1, SC-CCC-2

*Appendices to this Settlement Proposal:*
None

*Settlement Models:*
Settlement_Attachment_OEB_Chapter2Appendices_BHI

**Supporting Parties:** All

**Parties Taking No Position:** None

### 1.3 Is the addition of previously approved Incremental Capital Module project assets to rate base appropriate?

The Parties agree with the addition of previously approved Incremental Capital Module assets to BHI's rate base, subject to the disallowance of $160,692 (approximately 3%)

from the OEB's Decision and Order[1], which is included in the $2M reduction to opening rate base noted above in issue 1.2(a).

**Evidence:**

*Application:*
Exhibit 2, Section 2.8

*IRs:*
2-Staff-19, 2-Intervenor-28, 2-Intervenor-52

*Clarifying Question Responses:*
Staff-98, SEC-CQ-4

*Appendices to this Settlement Proposal:*
None

*Settlement Models:*
Settlement_Attachment_OEB_Chapter2Appendices_BHI

**Supporting Parties:** All
**Parties Taking No Position:** None

[1] EB-2024-0010, Decision and Order, December 17, 2024, p.27

## 2. OM&A

### 2.1 Are the proposed OM&A expenditures appropriate?

**Complete Settlement:**

For the purposes of settlement, the Parties agree to reduce BHI's 2026 Test Year OM&A envelope before Property Taxes by $4.20M from $30,157,314 to $25,957,314.

Table 2.1A identifies the changes in OM&A expenses as compared to that which was filed in BHI's original Application.

The settled reductions to each individual OM&A category are being provided by the Applicant for illustrative purposes. The Parties agree that the revised OM&A expenditures are reasonable to deliver customer services and upkeep the distribution system in accordance with good utility practice.

**Table 2.1A – Summary of OM&A Expenses -Variance**

| Description | 2021 Actuals | Application | Interrogatories | Variance | Settlement | Variance |
|---|---|---|---|---|---|---|
| | | a | b | c = b-a | d | e = d-b |
| Operations | $4,928,079 | $5,859,812 | $5,906,327 | $46,515 | $5,081,338 | ($824,989) |
| Maintenance | $5,763,352 | $8,043,725 | $8,043,725 | $0 | $6,741,706 | ($1,302,019) |
| **Sub-Total** | **$10,691,431** | **$13,903,537** | **$13,950,052** | **$46,515** | **$11,823,044** | **($2,127,008)** |
| Billing and Collecting | $2,683,766 | $3,363,904 | $3,363,904 | $0 | $2,911,162 | ($452,742) |
| Community Relations | $14,800 | $31,300 | $31,300 | $0 | $21,300 | ($10,000) |
| Administration and General | $7,737,404 | $12,741,360 | $12,812,058 | $70,698 | $11,201,808 | ($1,610,250) |
| **Sub-Total** | **$10,435,970** | **$16,136,564** | **$16,207,262** | **$70,698** | **$14,134,270** | **($2,072,992)** |
| **Total 2-JA** | **$21,127,400** | **$30,040,101** | **$30,157,314** | **$117,213** | **$25,957,314** | **($4,200,000)** |

**Evidence:**

*Application:*
Exhibit 1, Sections 1.2.4 D and 1.6
Exhibit 4

*IRs:*
4-Staff-38, 4-Staff-39, 4-Staff-40, 4-Staff-42, 4-Staff-43, 4-Staff-44, 4-Staff-45, 4-Staff-46, 4-Staff-47, 4-Staff-48, 4-Staff-49, 4-Staff-50, 4-Staff-51, 4-Staff-52, 4-Staff-53, 4-Staff-54, 4-Staff-56, 4-Staff-57, 4-Staff-58, 4-Staff-59, 4-Staff-60, 4-Staff-61, 4-Staff-62, 4-Staff-63, 4-Staff-64, 4-Staff-65, 4-Staff-66, 4-Staff-67, 1-Intervenor-2, 1-Intervenor-3, 1-Intervenor-5, 1-Intervenor-6, 1-Intervenor-7, 1-Intervenor-8, 1-Intervenor-9, 1-Intervenor-11, 4-Intervenor-92, 4-Intervenor-93, 4-Intervenor-94, 4-Intervenor-95, 4-Intervenor-96, 4-Intervenor-97, 4-Intervenor-98, 4-Intervenor-99, 4-Intervenor-100, 4-Intervenor-101, 4-Intervenor-102, 4-Intervenor-103, 4-Intervenor-104, 4-Intervenor-105, 4-Intervenor-106, 4-Intervenor-107, 4-Intervenor-108, 4-Intervenor-109, 4-Intervenor-110, 4-Intervenor-111, 4-

Intervenor-112, 4-Intervenor-113, 4-Intervenor-114, 4-Intervenor-115, 4-Intervenor-116, 4-Intervenor-117, 4-Intervenor-118, 4-Intervenor-119, 4-Intervenor-120, 4-Intervenor-123, 4-Intervenor-124, 4-Intervenor-125

*Clarifying Question Responses:*
Staff-106, Staff-107, Staff-108, Staff-109, Staff-110, Staff-111, Staff-112, Staff-113, SC-CCC-5, SC-CCC-6, SC-CCC-8

*Appendices to this Settlement Proposal:*
None

*Settlement Models:*
Settlement_Attachment_OEB_Chapter2Appendices_BHI

**Supporting Parties:** All
**Parties Taking No Position:** None

**2.2 Is the proposed shared services cost allocation methodology and the quantum appropriate?**

**Complete Settlement:**

The Parties agree with BHI's proposed shared services cost allocation methodology and the quantum.

**Evidence:**

*Application*:
Exhibit 4, Section 4.3.2

*IRs:*
4-Intervenor-121, 4-Intervenor-122

*Clarifying Question Responses:*
SC-CCC-9

*Appendices to this Settlement Proposal:*
None

*Settlement Models:*
Settlement_Attachment_OEB_Chapter2Appendices_BHI

**Supporting Parties:** All
**Parties Taking No Position:** None

## 3. Cost of Capital, PILs, and Revenue Requirement

### 3.1 Is the proposed cost of capital (interest on debt, return on equity) and capital structure appropriate?

**Complete Settlement:**

The Parties agree to use the proposed capital structure, and agree to update the return on equity, and short-term debt rates to incorporate those issued by the OEB as part of the 2026 Cost of Capital parameters which will be published in the fourth quarter of 2025.

The Parties agree that BHI will adjust the long-term debt rate on its 2026 debt issuance from 4.60% to the deemed long-term debt rate set by the OEB as part of the 2026 Cost of Capital parameters which will be published in the fourth quarter of 2025. The Parties further agree that BHI will not issue new long-term debt in 2025.

**Evidence:**

*Application:*
Exhibit 1 Section 1.2.4 E
Exhibit 5

*IRs:*
5-Staff-68, 5-Staff-69, 5-Staff-70, 5-Staff-71, 1-Intervenor-12, 5-Intervenor-126

*Clarifying Question Responses:*
SEC-CQ-5

*Appendices to this Settlement Proposal:*
None

*Settlement Models:*
Settlement_Attachment_OEB_Chapter2Appendices_BHI

**Supporting Parties:** All
**Parties Taking No Position:** None

### 3.2 Is the proposed PILs (or Tax) amount appropriate?

**Complete Settlement:**
The Parties accept the appropriateness of the Payments-in-Lieu of Taxes (PILs) and other tax-related components of BHI's revenue requirement as adjusted in the PILS Workform to reflect the changes set forth in this Settlement Proposal.

The Parties accept BHI's proposal that the accelerated CCA rules introduced by Bill C-97 were applied in the PILs tax models, and that the maximum accelerated CCA was claimed for 2026. Account 1592, PILs and Tax Variances, Sub-account CCA Changes, will continue to track the impact of further changes to the CCA rules over the IRM period.

The Parties agree to use the unsmoothed approach to account for the difference in revenue requirement as result of the phasing out period of the Accelerated Investment Incentive ("AII"). Specifically, the Parties agree that BHI will not increase PILs expense in the 2026 Test Year to smooth the impact of the phasing out period of the AII in 2028-2030; and BHI will use the Account 1592 sub-account CCA Changes to track the full revenue requirement impacts of the phasing out period of the AII over the IRM period. The balance in this sub-account is to be disposed of at BHI's next rebasing application.

**Evidence:**

*Application:*
Exhibit 1 Sections 1.2.4 A, 1.8.6
Exhibit 6

*IRs:*
6-Staff-73, 6-Staff-74, 6-Staff-75, 6-Staff-76, 6-Staff-77, 6-Staff-78

*Clarifying Question Responses:*
Staff-114, Staff-115

*Appendices to this Settlement Proposal:*
None

*Settlement Models:*
Settlement_Attachment_2026_PILS_Workform_BHI

**Supporting Parties:** All
**Parties Taking No Position:** None

**3.3 Is the proposed Other Revenue forecast appropriate?**

**Complete Settlement:**

For the purposes of settlement, the Parties agree to increase Other Revenue by $150,000 as compared to that which was filed in BHI's interrogatory responses, and as identified in Table 3.5H of this Settlement Proposal.

**Evidence:**

*Application:*
Exhibit 1 Sections 1.2.4 A
Exhibit 6, Section 6.3

*IRs:*
6-Staff-72, 6-Intervenor-127, 6-Intervenor-128, 6-Intervenor-129

*Clarifying Question Responses:*
None

*Appendices to this Settlement Proposal:*
None

*Settlement Models:*
Settlement_Attachment_OEB_Chapter2Appendices_BHI

**Supporting Parties:** All
**Parties Taking No Position:** None

**3.4 Have all impacts of any changes in accounting standards, policies, estimates and adjustments been properly identified and recorded, and is the rate-making treatment of each of these impacts appropriate?**

**Complete Settlement:**

The Parties agree that the impacts of any proposed changes in accounting standards, policies, estimates, and adjustments have been properly identified and recorded, and that the rate treatment of these impacts is appropriate. The Parties accept BHI's proposal to change the depreciation rate for USoA 1611 from 20% (5 years) to 10-20% (5-10 years) to reflect a change to the depreciation rate for BHI's CIS and GIS software from 5 years, as approved in BHI's last rebasing application[2], to 10 years.

**Evidence:**

*Application:*
Exhibit 1 Sections 1.8.9
Exhibit 2, Section 2.4

*IRs:*
2-Staff-28

*Clarifying Question Responses:*
Staff-100, CCC-1

*Appendices to this Settlement Proposal:*
None

*Settlement Models:*
Settlement_Attachment_2026_PILS_Workform_BHI

**Supporting Parties:** All
**Parties Taking No Position:** None

## 3.5 Is the proposed calculation of the Revenue Requirement appropriate?

**Complete Settlement:**

Subject to the modifications set out herein, the Parties agree with the proposed calculation of revenue requirement. The elements of Revenue Requirement are identified in Tables 3.5A to 3.5H below.

[2] EB-2020-0007

## Table 3.5A – Revenue Requirement

| Description | Application | Interrogatories | Variance | Settlement | Variance |
|---|---|---|---|---|---|
| | a | b | c = b-a | d | e = d-b |
| **Revenue Requirement** | | | | | |
| OM&A (Excluding Property Taxes and LEAP) | $29,975,101 | $30,092,314 | $117,213 | $25,892,314 | ($4,200,000) |
| Property Taxes | $375,892 | $375,892 | $0 | $375,892 | $0 |
| LEAP | $65,000 | $65,000 | $0 | $65,000 | $0 |
| Depreciation and Amortization | $10,046,886 | $10,065,714 | $18,828 | $9,652,371 | ($413,342) |
| **Total** | **$40,462,879** | **$40,598,920** | **$136,041** | **$35,985,577** | **($4,613,342)** |
| Regulated Return on Capital | $11,445,947 | $11,401,653 | ($44,294) | $11,091,448 | ($310,205) |
| Income Taxes Grossed Up | $931,830 | $925,602 | ($6,228) | $873,601 | ($52,001) |
| **Service Revenue Requirement** | **$52,840,656** | **$52,926,174** | **$85,518** | **$47,950,627** | **($4,975,547)** |
| Other Revenues | $4,355,525 | $4,339,019 | ($16,506) | $4,489,019 | $150,000 |
| **Base Revenue Requirement** | **$48,485,131** | **$48,587,155** | **$102,025** | **$43,461,608** | **($5,125,547)** |
| Distribution Revenue at Current Rates | $38,414,728 | $38,349,171 | ($65,557) | $38,789,248 | $440,077 |
| **Grossed Up Revenue Deficicency** | **$10,070,403** | **$10,237,984** | **$167,581** | **$4,672,360** | **($5,565,624)** |

## Table 3.5B – Rate Base

| Description | Application | Interrogatories | Variance | Settlement | Variance |
|---|---|---|---|---|---|
| | a | b | c = b-a | d | e = d-b |
| Average Gross Fixed Assets | $378,590,894 | $378,111,298 | ($479,596) | $374,486,297 | ($3,625,000) |
| Average Accumulated Depreciation | $209,633,086 | $209,666,481 | $33,395 | $210,813,464 | $1,146,983 |
| **Average Net Book Value** | **$168,957,808** | **$168,444,817** | **($512,992)** | **$163,672,833** | **($4,771,983)** |
| Working Capital Base | $208,567,641 | $207,419,166 | ($1,148,475) | $207,013,436 | ($405,730) |
| Working Capital Allowance (%) | 7.50% | 7.50% | 0.00% | 7.50% | 0.00% |
| **Working Capital Allowance ($)** | **$15,642,573** | **$15,556,437** | **($86,136)** | **$15,526,008** | **($30,430)** |
| **Rate Base** | **$184,600,382** | **$184,001,254** | **($599,127)** | **$179,198,840** | **($4,802,413)** |

## Table 3.5C – Cost of Power

| Description | Application | Interrogatories | Variance | Settlement | Variance |
|---|---|---|---|---|---|
| | a | b | c = b-a | d | e = d-b |
| Power Purchased | $107,290,082 | $105,708,104 | ($1,581,978) | $107,612,192 | $1,904,088 |
| Global Adjustment | $42,297,885 | $42,343,899 | $46,014 | $43,545,753 | $1,201,853 |
| Wholesale Market Service Charge | $9,211,026 | $9,118,656 | ($92,370) | $9,311,271 | $192,615 |
| Transmission - Network | $18,693,132 | $18,914,965 | $221,833 | $19,314,836 | $399,871 |
| Transmission - Connection | $14,106,259 | $14,005,337 | ($100,922) | $14,299,543 | $294,206 |
| Smart Meter Entity Charge | $347,296 | $346,933 | ($363) | $348,193 | $1,260 |
| Ontario Electricty Rebate | ($13,794,033) | ($13,551,935) | $242,098 | ($13,751,558) | ($199,624) |
| **Total** | **$178,151,648** | **$176,885,960** | **($1,265,688)** | **$180,680,230** | **$3,794,270** |

## Table 3.5D – Working Capital Allowance

| Description | Application | Interrogatories | Variance | Settlement | Variance |
|---|---|---|---|---|---|
| | a | b | c = b-a | d | e = d-b |
| Total Distribution Expenses | $30,415,993 | $30,533,206 | $117,213 | $26,333,206 | ($4,200,000) |
| Power Supply Expenses | $178,151,648 | $176,885,960 | ($1,265,688) | $180,680,230 | $3,794,270 |
| **Total Expenses for Working Capital** | **$208,567,641** | **$207,419,166** | **($1,148,475)** | **$207,013,436** | **($405,730)** |
| Working Capital Allowance % | 7.50% | 7.50% | 0.00% | 7.50% | 0.00% |
| **Total Working Capital Allowance** | **$15,642,573** | **$15,556,437** | **($86,136)** | **$15,526,008** | **($30,430)** |

**Table 3.5E – Capital Structure and Cost of Capital[3]**

| Description | Capitalization Ratios | | Rate | Return |
|---|---|---|---|---|
| | % | $ | % | $ |
| **Debt** | | | | |
| Long-term Debt | 56.0% | $100,351,351 | 4.34% | $4,360,023 |
| Short-term Debt | 4.0% | $7,167,954 | 3.91% | $280,267 |
| **Total Debt** | **60.0%** | **$107,519,304** | **4.32%** | **$4,640,290** |
| **Equity** | | | | |
| Common Equity | 40.0% | $71,679,536 | 9.00% | $6,451,158 |
| Preferred Shares | 0.0% | $0 | 0.00% | $0 |
| **Total Equity** | **40.0%** | **$71,679,536** | **9.00%** | **$6,451,158** |
| **Total** | **100.0%** | **$179,198,840** | **6.19%** | **$11,091,448** |

**Table 3.5F – Depreciation Expense**

| Description | Application | Interrogatories | Variance | Settlement | Variance |
|---|---|---|---|---|---|
| | a | b | c = b-a | d | e = d-b |
| Depreciation Expense | $10,046,886 | $10,065,714 | $18,828 | $9,652,371 | ($413,342) |

**Table 3.5G – PILs**

| Description | Application | Interrogatories | Variance | Settlement | Variance |
|---|---|---|---|---|---|
| | a | b | c = b-a | d | e = d-b |
| Taxes/PILs (Grossed up) | $931,830 | $925,602 | ($6,228) | $873,601 | ($52,001) |

**Table 3.5H – Other Revenue**

| Description | Application | Interrogatories | Variance | Settlement | Variance |
|---|---|---|---|---|---|
| | a | b | c = b-a | d | e = d-b |
| Specific Service Charges | ($270,029) | ($283,109) | ($13,080) | ($283,109) | $0 |
| Late Payment Charges | ($270,000) | ($270,000) | $0 | ($270,000) | $0 |
| Other Operating Revenues | ($2,884,844) | ($2,855,258) | $29,586 | ($2,839,922) | $15,336 |
| Other Income or Deductions | ($930,651) | ($930,651) | $0 | ($1,095,987) | ($165,336) |
| **Total** | **($4,355,525)** | **($4,339,019)** | **$16,506** | **($4,489,019)** | **($150,000)** |

**Evidence:**

*Application:*
Exhibit 1 Sections 1.2.4 A
Exhibit 6

*IRs:*
None

[3] Short-term debt rate, long-term debt rate and return-on-equity to be adjusted to reflect OEB 2026 Cost of Capital parameters to be published fourth quarter of 2025

*Clarifying Question Responses:*
None

*Appendices to this Settlement Proposal:*
None

*Settlement Models:*
Settlement_Attachment_2025_RRWF_BHI

**Supporting Parties:** All
**Parties Taking No Position:** None

# 4 Load Forecast

## 4.1 Is the proposed load forecast methodologies and the resulting load forecasts appropriate?

**Complete Settlement:**

The Parties agree to the proposed load forecast that was filed as part of VECC-CQ-12, which includes the COVID-19 variable for the 2026 load forecast for Residential, GS<50 and GS>50 customers, subject to the following adjustments:

a. *CDM Adjustments*: In respect of each rate class, the 2025 load forecast will not include CDM amounts related to the Local Initiatives program, and, the CDM amounts related to the Local Initiatives program proposed for the 2026 load forecast will be reduced by 50%.[4]

b. *Lost GS>50kW customer*: Update the Lost Loads due to the lost customer by 13,081 kW rather than 14,023 kW, to account for the lost GS>50 kW customer that ceased operations in early 2025.[5]

c. *Residential Customer Count*: For the purpose of settlement, the forecasted quantity of residential customers in 2026 will be increased by 250 customers, from 63,050 to 63,300.[6]

The resulting load forecast, customer counts and CDM adjustments are identified below in Tables 4.1A to 4.1C.

**Table 4.1A – Load Forecast**

| Rate Class | Application | | Interrogatories | | Settlement | |
|---|---|---|---|---|---|---|
| | kWh | kW | kWh | kW | kWh | kW |
| Residential | 554,448,693 | | 547,590,732 | | 550,433,963 | |
| GS<50 kW | 168,539,128 | | 165,906,773 | | 173,076,730 | |
| GS>50 kW | 732,505,202 | 1,968,903 | 732,355,269 | 1,974,932 | 753,189,947 | 2,031,031 |
| Streetlighting | 5,608,031 | 15,672 | 5,609,578 | 15,677 | 5,609,578 | 15,677 |
| Unmetered Scattered Load | 3,312,078 | | 3,307,852 | | 3,307,852 | |
| **Total** | **1,464,413,133** | **1,984,575** | **1,454,770,203** | **1,990,609** | **1,485,618,070** | **2,046,708** |

**Table 4.1B – Customer Forecast (Annual Average)**

| Rate Class | Determinant | Application | Interrogatories | Settlement |
|---|---|---|---|---|
| Residential | Customers | 63,119 | 63,050 | 63,300 |
| GS<50 kW | Customers | 5,823 | 5,786 | 5,786 |
| GS>50 kW | Customers | 952 | 956 | 956 |
| Streetlighting | Connections | 17,348 | 17,353 | 17,353 |
| Unmetered Scattered Load | Connections | 584 | 584 | 584 |

[4] 3-Staff-37.
[5] VECC-CQ-6 ; 3-Intervenor-86(c) ; application, Exhibit 3, p.51.
[6] VECC-CQ-11(a).

**Table 4.1C – CDM Adjustment**

| Rate Class | Application | | Interrogatories | | Settlement | |
|---|---|---|---|---|---|---|
| | kWh | kW | kWh | kW | kWh | kW |
| GS<50 kW | 4,009,240 | | 3,614,601 | | 2,202,893 | |
| GS>50 kW | 18,053,728 | 48,527 | 16,267,834 | 43,869 | 11,170,079 | 30,121 |
| **Total** | **22,062,969** | **48,527** | **19,882,435** | **43,869** | **13,372,972** | **30,121** |

**Evidence:**

*Application:*
Exhibit 1 Section 1.2.4 B
Exhibit 3

*IRs:*
3-Staff-31, 3-Staff-32, 3-Staff-33, 3-Staff-34, 3-Staff-35, 3-Staff-36, 3-Staff-37, 4-Staff-41, 1-Intervenor-9, 2-Intervenor-29, 3-Intervenor-81, 3-Intervenor-82, 3-Intervenor-83, 3-Intervenor-84, 3-Intervenor-85, 3-Intervenor-86, 3-Intervenor-87, 3-Intervenor-88, 3-Intervenor-89, 3-Intervenor-90, 3-Intervenor-91

*Clarifying Question Responses:*
Staff-105, VECC-CQ-1, VECC-CQ-2, VECC-CQ-3, VECC-CQ-4, VECC-CQ-5, VECC-CQ-6, , VECC-CQ-10, VECC-CQ-12

*Appendices to this Settlement Proposal:*
None

*Settlement Models:*
Settlement_Attachment_Load_Forecast_Model_BHI

**Supporting Parties:** All
**Parties Taking No Position:** None

## 5 Cost Allocation, Rate Design, and Other Charges

### 5.1 Are the proposed cost allocation methodology, allocations, and revenue-to-cost ratios, appropriate?

**Complete Settlement:**

The Parties agree with the cost allocation methodology and allocations as filed in this Settlement Proposal.

The Parties agree to adjust the revenue-to-cost ratios of the GS<50 kW, Streetlighting and Unmetered Scattered Load rate classes to the upper end of the Board's Policy range (i.e., to 120%). The Parties agree to allocate 100% of the associated revenue shortfall to the GS>50 kW rate class as the resulting revenue to cost ratio does not exceed either 100% or the revenue to cost ratio of any of the remaining classes. The Parties agree to the revenue-to-cost ratios identified in Table 5.1A below.

**Table 5.1A – Proposed Revenue to Cost Ratios**

| Rate Class | R:C Ratios from Cost Allocation Model - Line 75 Sheet O1 | Proposed R:C Ratio | Board Target Low | Board Target High |
|---|---|---|---|---|
| Residential | 98.75% | 98.75% | 85% | 115% |
| GS<50 kW | 124.00% | 120.00% | 80% | 120% |
| GS>50 kW | 91.41% | 93.51% | 80% | 120% |
| Streetlighting | 124.29% | 120.00% | 80% | 120% |
| USL | 133.39% | 120.00% | 80% | 120% |

**Evidence:**

*Application:*
Exhibit 1 Section 1.2.4 F
Exhibit 7
Exhibit 8

*IRs:*
7-Staff-80, 7-Intervenor-130, 7-Intervenor-131, 7-Intervenor-132, 7-Intervenor-133, 7-Intervenor-134, 8-Intervenor-135, 8-Intervenor-139, 8-Intervenor-146, 8-Intervenor-147

*Clarifying Question Responses:*
ED-CQ-8, ED-CQ-8, ED-CQ-9, ED-CQ-10, ED-CQ-11, ED-CQ-12, ED-CQ-13, ED-CQ-14, VECC-CQ-7, VECC-CQ-8, VECC-CQ-9

*Appendices to this Settlement Proposal:*
None
*Settlement Models:*
Settlement_Attachment_2026_Cost_Allocation_Model_v1.0_BHI

**Supporting Parties:** All
**Parties Taking No Position:** None

## 5.2 Is the proposed rate design, including fixed/variable splits, appropriate?

**Complete Settlement:**
The Parties agree that BHI's rate design proposed in its Application, including the proposed fixed/variable splits, are appropriate.

Table 5.2A below identifies the proposed distribution revenue charges.

**Table 5.2A – Proposed Fixed/Variable Distribution Charges**

| Rate Class | Unit | 2025 Distribution Rates Application | 2026 Distribution Rates Application | 2026 Distribution Rates Interrogatories | Variance | 2026 Distribution Rates Settlement | Variance | Fixed / Variable Split |
|---|---|---|---|---|---|---|---|---|
| | | | a | b | c = b-a | d | e = d-b | |
| **Residential** | | | | | | | | |
| Monthly Service Charge | $ | 32.64 | 41.19 | 41.35 | 0.16 | 36.57 | - 4.78 | 100.0% |
| Volumetric Charge | $/kWh | - | - | - | - | - | - | 0.0% |
| | | | | | | | | |
| **GS<50 kW** | | | | | | | | |
| Monthly Service Charge | $ | 29.29 | 36.96 | 37.11 | 0.15 | 28.76 | - 8.35 | 34.3% |
| Volumetric Charge | $/kWh | 0.0193 | 0.0244 | 0.0245 | 0.0001 | 0.0221 | - 0.0024 | 65.7% |
| | | | | | | | | |
| **GS>50 kW** | | | | | | | | |
| Monthly Service Charge | $ | 78.66 | 84.65 | 84.76 | 0.11 | 73.13 | - 11.63 | 8.8% |
| Volumetric Charge | $/kW | 3.8537 | 4.9155 | 4.9212 | 0.0057 | 4.4916 | - 0.4296 | 91.2% |
| | | | | | | | | |
| **Streetlighting** | | | | | | | | |
| Monthly Service Charge | $ | 0.65 | 0.78 | 0.81 | 0.03 | 0.70 | - 0.11 | 65.0% |
| Volumetric Charge | $/kW | 4.6705 | 5.5695 | 5.8023 | 0.2328 | 5.0359 | - 0.7664 | 35.0% |
| | | | | | | | | |
| **USL** | | | | | | | | |
| Monthly Service Charge | $ | 10.81 | 10.76 | 12.15 | 1.39 | 10.81 | - 1.34 | 54.9% |
| Volumetric Charge | $/kWh | 0.0188 | 0.0187 | 0.0212 | 0.0025 | 0.0188 | - 0.0024 | 45.1% |

**Evidence:**

*Application:*
Exhibit 1, Section 1.2.4 F
Exhibit 8, Section 8.1

*IRs:*
8-Intervenor-137

*Clarifying Question Responses:*
None

*Appendices to this Settlement Proposal:*
None

*Settlement Models:*
Settlement_Attachment_2026_RRWF_BHI
Settlement_Attachment_Tariff_Schedule_and_Bill_Impact_Model_BHI

**Supporting Parties:** All
**Parties Taking No Position:** None

### 5.3 Are the proposed Retail Transmission Service Rates appropriate?

**Complete Settlement:**
The Parties agree that the proposed Retail Transmission Service Rates are appropriate as identified in Table 5.3A below. BHI has updated the UTR and Hydro One sub transmission rates for 2025 in accordance with the OEB's rate orders EB-2024-0244 and EB-2024-0032 respectively[7]. The updated RTSR model includes the new EV Charging (EVC) rate for electric vehicle (EV) charging stations.

[7] 8-Staff-81

**Table 5.3A – Retail Transmission Service Rates**

| Proposed 2026 RTSR Network Service Rate | | | | | | |
|---|---|---|---|---|---|---|
| Rate Class | Unit | Application | Interrogatories | Variance | Settlement | Variance |
| | | a | b | c = b-a | d | e = d-b |
| Residential | kWh | 0.0122 | 0.0124 | 0.0002 | 0.0124 | - |
| GS<50 kW | kWh | 0.0117 | 0.0119 | 0.0002 | 0.0119 | - |
| GS>50 kW | kW | 4.8092 | 4.9016 | 0.0923 | 4.9016 | - |
| Streetlighting | kW | 3.5146 | 3.5821 | 0.0675 | 3.5821 | - |
| USL | kWh | 0.0117 | 0.0119 | 0.0002 | 0.0119 | - |

| Proposed 2026 RTSR Line and Transformation Connection Service Rate | | | | | | |
|---|---|---|---|---|---|---|
| Rate Class | Unit | Application | Interrogatories | Variance | Settlement | Variance |
| | | a | b | c = b-a | d | e = d-b |
| Residential | kWh | 0.0092 | 0.0092 | - | 0.0092 | - |
| GS<50 kW | kWh | 0.0084 | 0.0084 | - | 0.0084 | - |
| GS>50 kW | kW | 3.6523 | 3.6523 | - | 3.6523 | - |
| Streetlighting | kW | 0.0084 | 0.0084 | - | 0.0084 | - |
| USL | kWh | 2.5991 | 2.5991 | - | 2.5991 | - |

**Evidence:**

*Application:*
Exhibit 1 Sections 1.2.4 F
Exhibit 8, Section 8.2

*IRs:*
8-Staff-81, 8-Intervenor-138

*Clarifying Question Responses:*
None

*Appendices to this Settlement Proposal:*
None

*Settlement Models:*
Settlement_Attachment_2026_RTSR_Workform_BHI

**Supporting Parties:** All
**Parties Taking No Position:** None

**5.4 Are the proposed loss factors appropriate, considering OEB requirements and utility measures to cost-effectively reduce distribution losses?**

**Complete Settlement:**

The Parties agree that the proposed loss factors filed in BHI's interrogatory responses are appropriate, considering OEB requirements and utility measures to cost-effectively reduce distribution losses.

Appendix A, which forms a binding and integral part of this Settlement Proposal, contains commitments that are integral to this issue, including items 5 and 6.

**Table 5.4A – OEB Appendix 2-R**

| | Description | Historical Years | | | | | 5-Year Average |
|---|---|---|---|---|---|---|---|
| | | 2020 | 2021 | 2022 | 2023 | 2024 | |
| | ***Losses Within Distributor's System*** | | | | | | |
| A | "Wholesale" kWh delivered to distributor (higher value) | 1,560,832,200 | 1,570,411,100 | 1,582,272,268 | 1,538,474,828 | 1,566,109,307 | 1,563,619,941 |
| B | "Wholesale" kWh delivered to distributor (lower value) | 1,555,579,189 | 1,563,660,424 | 1,577,204,650 | 1,533,707,118 | 1,561,257,762 | 1,558,281,829 |
| C | microFIT kWh supplied to distributor | 9,882,707 | 9,718,702 | 9,647,170 | 8,663,953 | 9,039,538 | 9,390,414 |
| D | Other Embedded Generation | - | - | - | - | - | - |
| E | Portion of "Wholesale" kWh delivered to distributor for its Large Use Customer(s) | - | - | - | - | - | - |
| F | Net "Wholesale" kWh delivered to distributor = B + C + D - E | 1,565,461,896 | 1,573,379,126 | 1,586,851,820 | 1,542,371,071 | 1,570,297,300 | 1,567,672,243 |
| G | "Retail" kWh delivered by distributor | 1,504,792,712 | 1,513,843,506 | 1,531,698,249 | 1,484,415,329 | 1,511,587,889 | 1,509,267,537 |
| H | Portion of "Retail" kWh delivered by distributor to its Large Use Customer(s) | - | - | - | - | - | - |
| I | Net "Retail" kWh delivered by distributor = G - H | 1,504,792,712 | 1,513,843,506 | 1,531,698,249 | 1,484,415,329 | 1,511,587,889 | 1,509,267,537 |
| J | Loss Factor in Distributor's system = F / I | 1.0403 | 1.0393 | 1.0360 | 1.0390 | 1.0388 | 1.0387 |
| | ***Losses Upstream of Distributor's System*** | | | | | | |
| K | Supply Facilities Loss Factor | 1.0034 | 1.0043 | 1.0032 | 1.0031 | 1.0031 | 1.0034 |
| | ***Total Losses*** | | | | | | |
| L | Total Loss Factor = J x K | 1.0438 | 1.0438 | 1.0393 | 1.0423 | 1.0420 | 1.0422 |

**Table 5.4B – Total Loss Factors**

| Customer | Distribution Loss Factor | SFLF | Total Loss Factor |
|---|---|---|---|
| Secondary Metered Customer <5,000kW | 1.0387 | 1.0034 | 1.0422 |
| Primary Metered Customer <5,000kW | 1.0284 | 1.0034 | 1.0319 |

**Evidence:**

*Application:*
Exhibit 1 Sections 1.2.4 F
Exhibit 8, Section 8.8

*IRs:*
2-Staff-26, 8-Intervenor-136, 8-Intervenor-140, 8-Intervenor-141, 8-Intervenor-142, 8-Intervenor-143, 8-Intervenor-144, 8-Intervenor-145

*Clarifying Question Responses:*
ED-CQ-15, ED-CQ-16, ED-CQ-17

*Appendices to this Settlement Proposal:*
None

*Settlement Models:*
Settlement_Attachment_OEB_Chapter2Appendices_BHI

**Supporting Parties:** All
**Parties Taking No Position:** None

### 5.5 Are the Specific Service Charges and Retail Service Charge appropriate?

**Complete Settlement:**

The Parties agree that BHI's proposed Specific Service Charges, Retail Service Charges, and Pole Attachment Charges as identified in Appendix B – Proposed Tariff of Rates and Charges, are appropriate.

Appendix A, which forms a binding and integral part of this Settlement Proposal, contains commitments that are integral to this issue, including item no. 7.

**Evidence:**

*Application:*
Exhibit 1 Sections 1.2.4 F
Exhibit 8, Sections 8.3, 8.4, 8.5, 8.6, 8.7

*IRs:*
6-Intervenor-127, 6-Intervenor-128, 6-Intervenor-129

*Clarifying Question Responses:*
None

*Appendices to this Settlement Proposal:*
None

*Settlement Models:*
Settlement_Attachment_Tariff_Schedule_and_Bill_Impact_Model_BHI

**Supporting Parties:** All
**Parties Taking No Position:** None

### 5.6 Are rate mitigation proposals required and appropriate?

**Complete Settlement:**

The Parties agree to dispose of the deferral and variance accounts over a two-year period for rate mitigation purposes.

**Evidence:**

*Application:*
Exhibit 1 Sections 1.2.4 F, 1.2.4 H
Exhibit 8, Sections 8.11, 8.12

*IRs:*
None

*Clarification Question Responses:*
*None*

*Appendices to this Settlement Proposal:*
None

*Settlement Models:*
Settlement_Attachment_Tariff_Schedule_and_Bill_Impact_Model_BHI

## 6 Deferral and Variance Accounts

### 6.1 Are BHI's proposals for deferral and variance accounts, including the balances in the existing accounts and their disposition, requests for discontinuation of accounts, and the continuation of existing accounts, appropriate?

**Complete Settlement:**

Subject to the modification set out herein, the Parties agree that the proposals for deferral and variance accounts, including the balances in the existing accounts and their disposition, requests for discontinuation of accounts, and the continuation of existing accounts, as filed in this Settlement Proposal are appropriate. The balances proposed for disposition are identified in Table 6.1C below and are attached as Settlement_Attachment_DVA_Continuity_Schedule_BHI. Specifically, for the purposes of settlement:

a) *Group 1 Deferral and Variance Accounts ("DVAs"):* The Parties agree that the proposed balances in the existing accounts and their disposition as filed in the Application on April 16, 2025 are appropriate and agree that BHI dispose of its Group 1 DVAs on an interim basis as at December 31, 2024, including interest to December 31, 2025. BHI has updated the carrying charges based on the OEB prescribed interest rate for Q3 2025, as reflected in the updated DVA Continuity Schedule filed with this Settlement Proposal.

b) *Group 2 DVAs – Account 1509 Impacts Arising from the COVID-19 Emergency*: For the purposes of settlement, the Parties agree to record a balance of $115,987 for disposition in Account 1509 – Impacts Arising from the COVID-19 Emergency, rather than $320,439 as provided in the Application. This reflects no recovery of the 2021 incremental costs, and 50% recovery of the 2020 incremental costs incurred by BHI as a result of the COVID-19 Emergency, as these amounts were recorded in the account for which a 50% recovery rate applies.

   *Group 2 DVAs – Account 1592 PILS & Tax Variance – CCA Changes:* As discussed in Issue 3.2, the Parties agree to continue Sub-Account of 1592 - PILs and Tax Variances - CCA Changes to capture the revenue requirement impact of the accelerated CCA deductions for eligible property.

   For the purposes of settlement, the Parties agree to record the balance of $411,547 in Account 1592, CCA sub-account as identified in Table 6.1A below, which represents the revenue requirement impact of the phase-out of accelerated CCA deductions for eligible property in 2024 and 2025. Principal balances are updated for the capital expenditure and in-service additions changes identified in Issue 1.1 above, and carrying charges are updated to incorporate the OEB's prescribed interest rate for Q3 2025. The methodology BHI used to calculate the amount in question was based on actual additions for 2024 and 2025, not the 2024 and 2025 additions approved in BHI's last rebasing application[8]. For the purpose of settlement, the Parties accept the amount but not necessarily the methodology for calculating the amount in question.

**Table 6.1A – PILs & Tax Variance – CCA Changes**

| Description | 2024 | 2025 | Total |
|---|---|---|---|
| CCA in Rates | $10,274,262 | $9,858,152 | $20,132,414 |
| Actual CCA | $9,564,197 | $9,470,462 | $19,034,659 |
| Difference in CCA | $710,065 | $387,690 | $1,097,755 |
| Tax Impact @ 26.5% | $188,167 | $102,738 | $290,905 |
| **Grossed up PILs** | **$256,010** | **$139,779** | **$395,789** |
| Add Carrying Charges | | | $15,758 |
| **Total Requested for Disposition** | | | **$411,547** |

c) *Group 2 DVAs – Lost Revenue Adjustment Mechanism Variance Account ("LRAMVA") – Account 1568:* The Parties agree that no further entries to the LRAMVA are permitted at this time, consistent with the OEB's finding in its Decision and Order in BHI's 2024 rate application.[9] Notwithstanding the foregoing,. BHI reserves the right to seek the OEB's approval to request use of the LRAMVA (i) if BHI plans to conduct one or more activities that become eligible to be recorded in the LRAMVA based on future OEB policy developments, including but not limited to policy developments resulting from the ongoing Electricity Demand-Side Management Consultation (EB-2025-0156); and (ii) as part of a future rebasing application.

d) *Group 2 DVAs – All Other:* The Parties agree that the balances in the following DVAs as originally filed April 16, 2025 and updated to reflect the OEB prescribed Q3 2025 interest rate, as identified in Table 6.1C below, are appropriate:

- Pole Attachment Revenue Variance
- Customer Choice Initiative Costs
- Green Button Initiative Costs
- Capital Additions Dundas Street Road Widening Project
- Capital Additions Waterdown Rd Road Widening Project
- Collection Charge Lost Revenue
- Pension & OPEB Forecast Accrual versus Actual Cash Payment Differential Carrying Charges
- Extraordinary Event Costs (Z Factor) – 2022Wind Storm

[8] EB-2020-0007
[9] EB-2023-0008, Decision and Rate Order, December 14, 2023, p11

e) *Disposition Period*: The Parties agree to a disposition period of 2 years for all Group 1 and Group 2 DVAs.

f) *Continuation/Discontinuation of DVAs:* The Parties agree to continue/discontinue Group 2 DVAs as identified in Table 6.1B below:

**Table 6.1B – Status of Group 2 DVAs**

| Variance Account | USoA | Continue/ Discontinue |
|---|---|---|
| **Group 2** | | |
| Pole Attachment Revenue Variance | 1508 | Discontinue |
| Customer Choice Initiative Costs | 1508 | Discontinue |
| Local Initiatives Program Costs | 1508 | Discontinue |
| Green Button Initiative Costs | 1508 | Discontinue |
| Designated Broadband Project Impacts | 1508 | Discontinue |
| ULO Implementation Cost | 1508 | Discontinue |
| GOCA Variance Account | 1508 | Discontinue |
| LEAP EFA Funding Deferral Account | 1508 | Discontinue |
| Capital Additions Dundas Street Road Widening Project | 1508 | Discontinue |
| Capital Additions Waterdown Rd Road Widening Project | 1508 | Discontinue |
| Collection Charge Lost Revenue | 1508 | Discontinue |
| ICM - 2025 Dundas Street Road Widening Project | 1508 | Continue |
| Pension & OPEB Forecast Accrual versus Actual Cash Payment Differential Carrying Charges | 1522 | Continue |
| Extra-Ordinary Event Costs - 2022 Wind Storm (Z-Factor) | 1572 | Discontinue |
| PILs and Tax Variance for 2006 and Subsequent Years- Sub-account CCA Changes | 1592 | Continue |
| Lost Revenue Adjustment Mechanism Variance Account ("LRAMVA") | 1568 | Continue |
| Impacts Arising from the COVID-19 Emergency | 1509 | Discontinue |
| Incremental Cloud Computing Implementation Costs | 1511 | Discontinue |

g) *New DVAs* – The Parties agree to establish the following Group 2 DVAs:

- *System Access Variance Account* – As described in Issue 1.1 and Appendix C.
- *Cloud Computing Implementation Costs - ERP Replacement* – The Parties agree to establish a new deferral account to record cloud computing implementation and ongoing subscription costs in respect of BHI's Enterprise Resource Planning system ("ERP") replacement. Any amounts recorded in the account must be offset by the revenue requirement of the on-premise ERP replacement capital expenditures avoided during the IRM period through the implementation of a cloud-based ERP solution. For clarity, the avoided ERP replacement capital expenditures shall be no greater than $2,143,000, but may be lower if some amounts related to this project are capitalized in accordance with IFRS. The generic Incremental Cloud Computing Implementation Costs Account (Account 1511) will be closed in accordance with the Board's "Cost of Capital and Other Matters" Decision on March 27, 2025[10].

[10] EB-2024-0063, Section 3.8, p103

**Table 6.1C – Deferral and Variance Account Balances**

| Variance Account | Incorporate Principal Activity to: | USoA | Application | Interrogatories | Variance | Settlement | Variance |
|---|---|---|---|---|---|---|---|
| | | | a | b | c = b-a | d | e = d-b |
| **Group 1** | | | | | | | |
| Smart Metering Entity Charge Variance Account | 31-Dec-24 | 1551 | ($55,993) | ($55,993) | $0 | ($55,926) | $67 |
| RSVA - Wholesale Market Service Charge | 31-Dec-24 | 1580 | ($423,745) | ($423,745) | $0 | ($423,234) | $511 |
| Variance WMS – Sub-account CBR Class A | 31-Dec-24 | 1580 | $0 | $0 | $0 | $0 | $0 |
| Variance WMS – Sub-account CBR Class B | 31-Dec-24 | 1580 | $661,564 | $661,564 | $0 | $660,760 | ($804) |
| RSVA - Retail Transmission Network Charge | 31-Dec-24 | 1584 | $301,641 | $301,641 | $0 | $301,266 | ($374) |
| RSVA - Retail Transmission Connection Charge | 31-Dec-24 | 1586 | ($274,469) | ($274,469) | $0 | ($274,140) | $329 |
| RSVA - Power (excluding Global Adjustment) | 31-Dec-24 | 1588 | $722,864 | $722,864 | $0 | $721,999 | ($865) |
| RSVA - Global Adjustment | 31-Dec-24 | 1589 | $3,026,767 | $3,026,767 | $0 | $3,023,132 | ($3,635) |
| **Total Group 1 Balances** | | | **$3,958,628** | **$3,958,628** | **$0** | **$3,953,857** | **($4,771)** |
| **Group 2** | | | | | | | |
| Pole Attachment Revenue Variance | 31-Dec-25 | 1508 | $283,642 | $283,642 | $0 | $283,332 | ($310) |
| Customer Choice Initiative Costs | 31-Dec-25 | 1508 | $158,757 | $158,757 | $0 | $158,589 | ($168) |
| Green Button Initiative Costs | 31-Dec-25 | 1508 | $260,320 | $260,320 | $0 | $260,108 | ($212) |
| Capital Additions Dundas Street Road Widening Project | 31-Dec-25 | 1508 | ($15,264) | ($15,264) | $0 | ($15,259) | $5 |
| Capital Additions Waterdown Rd Road Widening Project | 31-Dec-25 | 1508 | ($6,032) | ($6,032) | $0 | ($6,026) | $6 |
| Collection Charge Lost Revenue | 30-Apr-21 | 1508 | $835,348 | $835,348 | $0 | $834,442 | ($906) |
| Pension & OPEB Forecast Accrual versus Actual Cash Payment Differential Carrying Charges | n/a | 1522 | ($77,656) | ($77,656) | $0 | ($77,656) | $0 |
| Extra-Ordinary Event Costs - 2022 Wind Storm (Z-Factor) | 31-Dec-24 | 1572 | $4,749 | $4,749 | $0 | $4,749 | $0 |
| PILs and Tax Variance for 2006 and Subsequent Years- Sub-account CCA Changes | 31-Dec-25 | 1592 | $450,322 | $450,322 | $0 | $411,547 | ($38,775) |
| Impacts Arising from the COVID-19 Emergency | 31-Dec-20 | 1509 | $320,439 | $320,439 | $0 | $115,987 | ($204,452) |
| **Total Group 2 Balances** | | | **$2,214,625** | **$2,214,625** | **$0** | **$1,969,814** | **($244,812)** |
| **Total DVA Balances** | | | **$6,173,254** | **$6,173,254** | **$0** | **$5,923,671** | **($249,583)** |

The updated DVA rate riders are provided in Tables 6.1D to 6.1H below.

**Table 6.1D – Group 1 DVA Rate Rider by Rate Class (Excluding Account 1589)**

| Rate Class | Billing Determinant | kWh/kWs | Allocated Group 1 Balance (excluding 1589) | Rate Rider for Deferral/ Variance Accounts |
|---|---|---|---|---|
| Residential | kWh | 550,433,963 | 69,520 | 0.0001 |
| GS<50 kW | kWh | 173,076,730 | 33,266 | 0.0001 |
| GS>50 kW | kW | 2,031,031 | 165,222 | 0.0407 |
| Unmetered Scattered Load | kWh | 3,307,852 | 726 | 0.0001 |
| Street Lighting | kW | 15,677 | 1,231 | 0.0392 |
| **Total** | | | **$269,965** | |

**Table 6.1E – Account 1589 Rate Riders by Rate Class**

| Rate Class | Billing Determinant | kWh/kWs | Allocated GA Balance | Rate Rider for GA |
|---|---|---|---|---|
| Residential | kWh | 3,302,604 | 19,804 | 0.0030 |
| GS<50 kW | kWh | 17,999,980 | 107,936 | 0.0030 |
| GS>50 kW | kWh | 464,212,843 | 2,783,635 | 0.0030 |
| Unmetered Scattered Load | kWh | - | - | - |
| Street Lighting | kWh | 5,564,701 | 33,369 | 0.0030 |
| **Total** | | | **$2,944,744** | |

**Table 6.1F – Sub-account 1580 CBR Class B Rate Rider by Rate Class**

| Rate Class | Billing Determinant | kWh/kWs | Allocated Sub-account 1580 CBR Class B Balance | Rate Rider for Sub-account 1580 CBR Class B |
|---|---|---|---|---|
| Residential | kWh | 550,433,963 | 277,872 | 0.0003 |
| GS<50 kW | kWh | 173,076,730 | 87,373 | 0.0003 |
| GS>50 kW | kW | 1,554,107 | 276,551 | 0.0890 |
| Unmetered Scattered Load | kWh | 3,307,852 | 1,670 | 0.0003 |
| Street Lighting | kW | 15,677 | 2,832 | 0.0903 |
| **Total** | | | **$646,299** | |

**Table 6.1G – Group 2 DVA Rate Riders by Rate Class (excluding 1509)**

| Rate Class | Billing Determinant | # customers/ kWh/kW | Allocated Group 2 Balance | Rate Rider for Group 2 Accounts |
|---|---|---|---|---|
| Residential | # of Customers | 63,300 | 761,073 | 0.50 |
| GS<50 kW | kWh | 173,076,730 | 220,502 | 0.0006 |
| GS>50 kW | kW | 2,031,031 | 860,481 | 0.2118 |
| Unmetered Scattered Load | kWh | 3,307,852 | 4,387 | 0.0007 |
| Street Lighting | kW | 15,677 | 7,383 | 0.2355 |
| **Total** | | | **$1,853,826** | |

**Table 6.1H – Account 1509 Rate Riders by Rate Class**

| Rate Class | Billing Determinant | # customers/ kWh/kW | Allocated Account 1509 Balance | Rate Rider for Account 1509 |
|---|---|---|---|---|
| Residential | # of Customers | 63,300 | 73,356 | 0.05 |
| GS<50 kW | kWh | 5,786 | 15,366 | 0.11 |
| GS>50 kW | kW | 956 | 26,306 | 1.15 |
| Unmetered Scattered Load | kWh | 584 | 364 | 0.03 |
| Street Lighting | kW | 17,353 | 595 | 0.00 |
| **Total** | | | **$115,987** | |

**Evidence:**

*Application:*
Exhibit 1 Sections 1.6 G, 1.10
Exhibit 9

*IRs:*
9-Staff-82, 9-Staff-83, 9-Staff-84, 9-Staff-85, 9-Staff-86, 9-Staff-87, 9-Staff-88, 9-Staff-89, 9-Staff-90, 9-Staff-91, 9-Staff-92, 9-Staff-93, 9-Staff-94, 9-Staff-95, 9-Intervenor-148, 9-Intervenor-149, 9-Intervenor-150, 9-Intervenor-151, 9-Intervenor-152, 9-Intervenor-153

*Clarifying Question Responses:*
Staff-116, Staff-117, Staff-118, Staff-119, Staff-120, SC-CCC-5

*Appendices to this Settlement Proposal:*
None

*Settlement Models:*
Settlement_Attachment_DVA_Continuity_Schedule_BHI

Settlement_Attachment_Tariff_Schedule_and_Bill_Impact_Model_BHI

**Supporting Parties:** All
**Parties Taking No Position:** None

# 7 Other

## 7.1 Is the proposed effective date appropriate?

**Complete Settlement:**

The Parties agree that the proposed effective date of January 1, 2026 is appropriate.

**Evidence:**

*Application:*
Exhibit 1 Section 1.3.8

*IRs:*
None

*Clarifying Question Responses:*
None

*Appendices to this Settlement Proposal:*
None

*Settlement Models:*
None

**Supporting Parties:** All
**Parties Taking No Position:** None

## 7.2 Has the applicant responded appropriately to all relevant OEB directions from previous proceedings?

**Complete Settlement:**
The Parties agree that BHI has responded appropriately to all relevant OEB directions from previous proceedings outlined in the OEB's Decision and Order approving the settlement proposal in EB-2020-0007.[11]

[11] EB-2020-0007, Decision and Order, BHI (April 15, 2021).

**Evidence:**

*Application:*
Exhibit 1 Section 1.3.10
DSP, Sections 5.2.3.1.1, 5.2.3.1.4
Exhibit 8, Appendix C
Exhibit 9, Sections 9.1.11, 9.1.12

*IRs:*
9-Staff-94

*Clarifying Question Responses:*
Staff-120

*Appendices to this Settlement Proposal:*
None

*Settlement Models:*
None

**Supporting Parties:** All
**Parties Taking No Position:** None

**7.3 Is the proposal for an Advanced Capital Module to replace the existing Supervisory Control and Data Acquisition system and implement a fully integrated Advanced Distribution Management System appropriate?**

**Complete Settlement:**
The Parties agree with BHI's proposal for an ACM to replace BHI's Supervisory Control and Data Acquisition system and procure and implement an Advanced Distribution Management System as provided in the Application and interrogatory responses, provided that BHI will not introduce it as an in-service addition any earlier than January 1, 2028 rather than in 2027 as proposed in the Application and interrogatory responses.

**Evidence:**

*Application:*
Exhibit 2 Section 2.7

*IRs:*
2-Staff-12, 4-Staff-55, 2-Intervenor-23, 2-Intervenor-24, 2-Intervenor-25, 2-Intervenor-26, 2-Intervenor-27

*Clarifying Question Responses:*
SEC-CQ-1, SEC-CQ-2

*Appendices to this Settlement Proposal:*
None

*Settlement Models:*
None

**Supporting Parties:** All
**Parties Taking No Position:** None

## Appendix A

## BHI Settlement Commitments

1. **DSP Metrics:** BHI will continue to track the two new reliability metrics and three new unit cost metrics agreed to as part of the Settlement Proposal in EB-2020-0007 (Page 13).

2. **Reactive and Proactive:** BHI will continue to track proactive versus reactive asset replacement (quantity and total expenditures for both reactive and proactive replacements) for the following asset classes agreed to as part of the Settlement Proposal in EB-2020-0007 (Page 13):
    a. Pole Replacement

    b. Underground Rebuilds

    c. Switchgear Replacement

    d. Station Transformer Replacement

    e. MS Feeders Cable Replacement

    f. Distribution Transformer Replacement

    g. Switch Replacement

3. **General Commitments:**

    a. BHI confirms that it is committed to enabling The City of Burlington Climate Action Plan and the Burlington Distribution System Sustainability Plan.

    b. BHI will undertake all reasonable efforts to collaborate with the IESO, the City of Burlington and other relevant stakeholders to support eDSM program delivery within its service territory. BHI will report on its efforts at the next rebasing.

4. **Energy transition planning:** BHI will consider system demand and capacity to ensure its system can meet future customer and energy transition needs, including DERs. This work will be considered in the development of BHI's next DSP.

5. **Work commitment:** BHI shall carry out the work and activities related to grid modernization, electric vehicles, and cost-effective distribution loss reductions as described in 1-Intervenor-1(b)(items 2-4), 2-Intervenor-36 (f), and 8-Intervenor-140 subject to the following caveats:

a. That complete execution of the work does not hinder BHI's ability to re-allocate capital to manage to budget envelopes to address unforeseen contingencies;
b. The complete execution of the work is contingent on technical feasibility and BHI's ability to procure the necessary equipment;
c. Conversion of the existing single-phase circuit (HOWD F3) to the 27.6 kV voltage level is excluded; and
d. BHI commits to keeping the power factor above 90% per the DSC.

6. **Distribution losses study continuation (issues: loss factors, operating costs, capital costs):** BHI shall conduct a further study during the next rate period to build on the learnings from its June 21, 2023 report, including:
    a. Update/validate CYME with latest SCADA/AMI (peak and typical), then screen specific feeders and rank by peak line-loss > 4%, and phase imbalance > 10% to produce a prioritized shortlist.

    b. Evaluate feeders with >10% current imbalance for potential targeted load balancing, with emphasis on cost-effective cases.

    c. Conduct additional feeder reconfiguration scenarios where the 2023 study showed potential. Run switching/supply-point transfer options with protection/voltage/loading checks and quantify loss reduction and operational impacts.

7. **DER connection charges (issue: rate design, service charges):** BHI shall endeavour to reduce DER connection costs, including but not limited to connection impact assessment costs. This shall include reviewing the practices of Ontario distributors that are leading in efforts to reduce interconnection costs within the next 12 months, including those that can secure lower costs for smaller DER connections and have a graduated fee schedule. BHI shall report on the outcome of this work in its next rates case, including a comparison of its charges with the leading distributors noted above, where available. This work shall be subject to any relevant OEB consultations.

# Appendix B

## Proposed Tariff of Rates and Charges

# Burlington Hydro Inc.

## TARIFF OF RATES AND CHARGES

### Effective and Implementation Date January 1, 2026

**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2025-0051**

## RESIDENTIAL SERVICE CLASSIFICATION

This classification applies to low voltage connection assets that operate at 750 volts or less and supply electrical energy to residential customers where such energy is used exclusively in separately 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 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 | $ | 36.57 |
| Rate Rider for Disposition of Account 1509 - effective until December 31, 2027 | $ | 0.05 |
| Rate Rider for Group 2 Deferral/Variance Account Balances - effective until December 31, 2027 | $ | 0.50 |
| Smart Metering Entity Charge - effective until December 31, 2027 | $ | 0.42 |
| Rate Rider for Disposition of Deferral/Variance Accounts - effective until December 31, 2027 | $/kWh | 0.0001 |
| Rate Rider for Disposition of Capacity Based Recovery (CBR) Account Applicable only for Class B Customers - effective until December 31, 2027 | $/kWh | 0.0003 |
| Rate Rider for Disposition of Global Adjustment Account - Applicable to Non-RPP Customers Only - effective until December 31, 2027 | $/kWh | 0.0030 |
| Retail Transmission Rate - Network Service Rate | $/kWh | 0.0124 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kWh | 0.0092 |

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR | $/kWh | 0.0041 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0015 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Burlington Hydro Inc.

## TARIFF OF RATES AND CHARGES

### Effective and Implementation Date January 1, 2026

**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2025-0051**

## GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION

This classification applies to low voltage connection assets that operate at 750 volts or less and supply electricity to general service customers whose monthly average peak demand during a calendar year is less than, or forecast by BHI 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 | $ | 28.76 |
| Rate Rider for Disposition of Account 1509 - effective until December 31, 2027 | $ | 0.11 |
| Smart Metering Entity Charge - effective until December 31, 2027 | $ | 0.42 |
| Distribution Volumetric Rate | $/kWh | 0.0221 |
| Rate Rider for Disposition of Deferral/Variance Accounts - effective until December 31, 2027 | $/kWh | 0.0001 |
| Rate Rider for Disposition of Capacity Based Recovery (CBR) Account Applicable only for Class B Customers - effective until December 31, 2027 | $/kWh | 0.0003 |
| Rate Rider for Disposition of Global Adjustment Account - Applicable to Non-RPP Customers Only - effective until December 31, 2027 | $/kWh | 0.0030 |
| Rate Rider for Group 2 Deferral/Variance Account Balances - effective until December 31, 2027 | $/kWh | 0.0006 |
| Retail Transmission Rate - Network Service Rate | $/kWh | 0.0119 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kWh | 0.0084 |

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR | $/kWh | 0.0041 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0015 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Burlington Hydro Inc.
## TARIFF OF RATES AND CHARGES
### Effective and Implementation Date January 1, 2026
**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2025-0051**

## GENERAL SERVICE 50 TO 4,999 KW SERVICE CLASSIFICATION

This classification applies to general service customers with a monthly average peak demand during a calendar year equal to or greater than, or is forecast by Burlington Hydro Inc. 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.

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 73.13 |
| Rate Rider for Disposition of Account 1509 - effective until December 31, 2027 | $ | 1.15 |
| Distribution Volumetric Rate | $/kW | 4.4916 |
| Rate Rider for Disposition of Deferral/Variance Accounts - effective until December 31, 2027 | $/kW | 0.0407 |
| Rate Rider for Disposition of Capacity Based Recovery (CBR) Account Applicable only for Class B Customers - effective until December 31, 2027 | $/kW | 0.0890 |
| Rate Rider for Disposition of Global Adjustment Account - Applicable to Non-RPP Customers Only - effective until December 31, 2027 | $/kWh | 0.0030 |

# Burlington Hydro Inc.
## TARIFF OF RATES AND CHARGES
### Effective and Implementation Date January 1, 2026
**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2025-0051**

| | | |
|---|---|---|
| Rate Rider for Group 2 Deferral/Variance Account Balances - effective until December 31, 2027 | $/kW | 0.2118 |
| Retail Transmission Rate - Network Service Rate - Interval Metered | $/kW | 4.9016 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate - Interval Metered | $/kW | 3.6523 |

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR | $/kWh | 0.0041 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0015 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Burlington Hydro Inc.
## TARIFF OF RATES AND CHARGES
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**EB-2025-0051**

## UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

This classification applies to low voltage connection assets that operate at 750 volts or less and supply electricity to general service customers whose monthly average peak demand during a calendar year is less than, or forecast by Burlington Hydro Inc. 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 customer will provide detailed manufacturer information/documentation with regard to electrical demand/consumption of the proposed unmetered load. 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 | $ | 10.81 |
| Rate Rider for Disposition of Account 1509 - effective until December 31, 2027 | $ | 0.03 |
| Distribution Volumetric Rate | $/kWh | 0.0188 |
| Rate Rider for Disposition of Deferral/Variance Accounts - effective until December 31, 2027 | $/kWh | 0.0001 |
| Rate Rider for Disposition of Capacity Based Recovery (CBR) Account Applicable only for Class B Customers - effective until December 31, 2027 | $/kWh | 0.0003 |
| Rate Rider for Group 2 Deferral/Variance Account Balances - effective until December 31, 2027 | $/kWh | 0.0007 |
| Retail Transmission Rate - Network Service Rate | $/kWh | 0.0119 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kWh | 0.0084 |

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR | $/kWh | 0.0041 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0015 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Burlington Hydro Inc.

## TARIFF OF RATES AND CHARGES

### Effective and Implementation Date January 1, 2026

**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2025-0051**

## STREET LIGHTING SERVICE CLASSIFICATION

This classification refers to roadway lighting customers such as the City of Burlington, the Regional Municipality of Halton, Ministry of Transportation and private roadway lighting, controlled by photo cells. The daily consumption for these customers will be based on the calculated connected load times the required night time or 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 device) | $ | 0.70 |
| Rate Rider for Disposition of Account 1509 - effective until December 31, 2027 | $ | 0.00 |
| Distribution Volumetric Rate | $/kW | 5.0359 |
| Rate Rider for Disposition of Deferral/Variance Accounts - effective until December 31, 2027 | $/kW | 0.0392 |
| Rate Rider for Disposition of Capacity Based Recovery (CBR) Account Applicable only for Class B Customers - effective until December 31, 2027 | $/kW | 0.0903 |
| Rate Rider for Disposition of Global Adjustment Account - Applicable to Non-RPP Customers Only - effective until December 31, 2027 | $/kWh | 0.0030 |
| Rate Rider for Group 2 Deferral/Variance Account Balances - effective until December 31, 2027 | $/kW | 0.2355 |
| Retail Transmission Rate - Network Service Rate | $/kW | 3.5821 |
| Retail Transmission Rate - Line Connection Service Rate | $/kW | 2.5991 |

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR | $/kWh | 0.0041 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0015 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Burlington Hydro Inc.
## TARIFF OF RATES AND CHARGES
### Effective and Implementation Date January 1, 2026
**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2025-0051**

## 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 | $ | 5.00 |

## 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

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 |
| Credit reference/credit check (plus credit agency costs) | $ | 15.00 |
| Statement of account | $ | 15.00 |
| Account set up charge/change of occupancy charge (plus credit agency costs if applicable) | $ | 30.00 |

| | | |
|---|---|---|
| Returned cheque (plus bank charges) | $ | 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

| | | |
|---|---|---|
| Temporary service - install & remove - overhead - no transformer | $ | 500.00 |
| Specific charge for wireline access to the power poles - $/pole/year | $ | 40.59 |
| (with the exception of wireless attachments) | | 40.59 |

## RETAIL SERVICE CHARGES (if applicable)

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 | $ | 125.72 |
| Monthly Fixed Charge, per retailer | $ | 50.29 |
| Monthly Variable Charge, per customer, per retailer | $/cust. | 1.24 |
| Distributor-consolidated billing monthly charge, per customer, per retailer | $/cust. | 0.74 |
| Retailer-consolidated billing monthly credit, per customer, per retailer | $/cust. | (0.74) |
| Service Transaction Requests (STR) | | |
| Request fee, per request, applied to the requesting party | $ | 0.63 |
| Processing fee, per request, applied to the requesting party | $ | 1.24 |
| 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) | $ | 5.03 |

# Burlington Hydro Inc.

## TARIFF OF RATES AND CHARGES

### Effective and Implementation Date January 1, 2026

**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2025-0051**

| | | |
|---|---|---|
| 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) | $ | 2.51 |

## 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 | 1.0422 |
| Total Loss Factor - Primary Metered Customer < 5,000 kW | 1.0319 |

# Appendix C

## Accounting Orders

**Accounting Order #1**
**Burlington Hydro**
**Inc. EB-2025-0051**

**Account 1508 Sub-account – System Access Variance Account - Revenue Requirement Differential Variance Account**

Effective January 1, 2026, BHI shall establish a new variance account: Account 1508 Sub-account – System Access Variance Account - Revenue Requirement Differential Variance Account ("System Access Variance Account" or "SAVA"). The purpose of this sub-account is to record the revenue requirement associated with the difference between actual 2026 System Access capital additions and the forecasted 2026 System Access capital additions in the Application, net of capital contributions, in the 2026 Test Year and the resulting impact during the IRM period. The baseline net capital additions used to determine any variance will be $13,500,384. The account will be asymmetrical, such that (i) the maximum amount of additional 2026 System Access net capital additions used to calculate the revenue requirement recorded in the account will be limited to $2M above the baseline, reflecting BHI's forecast budget in the application, while (ii) the revenue requirement impact of the aggregate amounts of actual 2026 System Access net capital additions that are less than the baseline will be fully recorded in the account.

If the revenue requirement impact is higher than forecast in the 2026 Test Year (i.e., the actual System Access net capital additions in the Test Year exceed forecasted System Access net capital additions up to a maximum of $2M), BHI will make a debit entry in the System Access Variance Account representing a collection from ratepayers. If the revenue requirement impact is lower than forecast in the 2026 Test Year (i.e., the actual System Access net capital additions in the 2026 Test Year are lower than forecasted System Access net capital additions), BHI will make a credit entry in the System Access Variance Account representing a refund to ratepayers. The revenue requirement impact includes depreciation, interest, ROE and PILs. To calculate the PILs expense, the Capital Cost Allowance ("CCA") under the Accelerated Investment Incentive shall be used, which is consistent with the treatment of the CCA on the net capital additions in the 2026 Test Year. All components of cost of capital will use the weighted average cost of capital, as approved in BHI's Cost of Service Application EB-2025-0051.

For each rate year from 2027 until BHI's next rebasing, BHI will make further entries into the account equal to the revenue requirement impact in the 2026 Test Year associated with the difference between actual and budgeted net capital additions in respect of System Access (i.e. the 2026 debit or credit entry described above), escalated annually by the OEB Price Cap IR annual adjustment (Inflation minus X-factor) in effect for that year as well as growth in billing determinants.

The System Access Variance account shall be disposed of on a final basis as part of any Advanced Capital Module ("ACM") or Incremental Capital Module ("ICM") application that BHI may file during the IRM period, or at its next rebasing application. This account will accrue carrying charges at OEB-prescribed rates until final disposition.

The following are sample journal entries should actual System Access in-service net capital additions exceed budgeted System Access in-service net capital additions in the 2026 Test Year.

| | Debit | Credit |
|---|---|---|
| DR. Account 1508 - Sub-account SAVA – Depreciation | x,xxx.xx | |
| DR. Account 1508 - Sub-account SAVA – Deemed Interest Expense | x,xxx.xx | |
| DR. Account 1508 - Sub-account SAVA – Return on Equity | x,xxx.xx | |
| DR. Account 1508 - Sub-account SAVA – PILs | x,xxx.xx | |
| CR. Account 4080 - Distribution Services Revenue | | x,xxx.xx |

| | | |
|---|---|---|
| DR. Account 1508 - Sub-account SAVA – Carrying Charges | x,xxx.xx | |
| CR. Account 6035 - Interest Expense | | x,xxx.xx |

**Accounting Order #2**
**Burlington Hydro**
**Inc. EB-2025-0051**

**Account 1508 – Cloud Computing Implementation Costs - ERP Replacement**

The Parties agree to establish a new deferral account to record cloud computing implementation and ongoing subscription costs in respect of BHI's Enterprise Resource Planning system ("ERP") replacement. Any amounts recorded in the account must be offset by the revenue requirement of the on-premise ERP replacement capital expenditures avoided during the IRM period through the implementation of a cloud-based ERP solution. For clarity, the avoided ERP replacement capital expenditures shall be no greater than $2,143,000, but may be lower if some amounts related to this project are capitalized in accordance with IFRS. The generic Incremental Cloud Computing Implementation Costs Account (Account 1511) will be closed in accordance with the Board's "Cost of Capital and Other Matters" Decision on March 27, 2025[1].

The following are sample journal entries to record cloud computing implementation costs in respect of BHI's ERP replacement:

Dr. 1508 Cloud Computing Implementation Costs – ERP Replacement

Cr. XXXX OM&A Account(s) associated with cloud costs, as applicable

*To record cloud computing ERP implementation costs incurred*

Dr. 4080 Distribution Revenue

Cr. 1508 Cloud Computing Implementation Costs – ERP Replacement, Sub-account Revenue Requirement

*To record the revenue requirement impact of the cloud computing ERP implementation costs which otherwise would have been recorded in capital*

[1] EB-2024-0063, Section 3.8, p103

``

Dr. 1508 Cloud Computing Implementation Costs – ERP Replacement, Sub-account Carrying Charges

Cr. 6035 Other Interest Expense

*To record the carrying charges on the net monthly opening balance in Account 1508 - Cloud Computing Implementation Costs – ERP Replacement*

The net monthly opening balance of Account 1508 Cloud Computing Implementation Costs – ERP Replacement shall be used to calculate the carrying charges in this account. The net monthly opening balance shall be calculated as:

1. The cumulative cloud computing ERP implementation costs incurred and recorded in Account 1508 Cloud Computing Implementation Costs – ERP Replacement

   net of

2. The cumulative revenue requirement impact of the cloud computing ERP implementation costs which otherwise would have been recorded in capital and recorded in Account 1508 Cloud Computing Implementation Costs – ERP Replacement, Sub-account Revenue Requirement

# Appendix D

## Pre-Settlement Conference Clarification Questions

**Staff 96**

**Primary Station Switchgear**

**Ref 1: DSP Appendix A: Material Investment Summary Documents, Material Investment Summary for Switchgear Replacement and Substation Automation**

**Ref 2: Response to 2-Intervenor-63**

Question(s):

a) At reference 1, Burlington Hydro states that it plans to replace one to two primary station switchgear annually over the DSP period. At reference 2 in Table 1, table 1 shows that it plans to replace four switchgears in 2026 and three each year in the remainder of the term. Please confirm how many switchgears Burlington Hydro Plans to replace each year from 2026-2030.

**Response:**

a) BHI plans to replace 4 switchgears in 2026 and 3 each year for the remainder of the rate period.

**Staff-97**

**Capital Contributions**

**Ref 1: Response to 2-Staff-4**

Question(s):

a) Please explain how the capital contribution for the Major Transit Station Area Development project was calculated.

**Response:**

a) Please refer to BHI's response to clarification question SC-CCC-4.

**Staff-98**

**Previously approved ICM funding**

**Ref 1: Response to 2-Staff-19**

**Question(s):**

a) Please explain the reasons for the revised in-service date for the Dundas Street Road Widening project (Northampton Boulevard to Guelph Line section), which has been deferred from 2025 to 2026.
b) Please summarize the original scope of work planned for completion in 2025 for the Northampton Boulevard to Guelph Line section, and outline any changes to the scope resulting from the revised 2026 in-service date.
c) Please clarify the factors that led to the change in the project cost for the Dundas Street Road Widening project (Northampton Boulevard to Guelph Line and Guelph Line to Kerns Road sections) as provided in Chapter 2 Appendices from the prefiled evidence to the response to 1-Staff-01:
    - Northampton Boulevard to Guelph Line: $4.09M (prefiled evidence) to $3.79M (response to 1-Staff-01)
    - Guelph Line to Kerns Rd.: $8.06M (prefiled evidence) to $9.18M (response to 1-Staff-01)
d) Please provide a detailed project schedule and cost breakdown for the Dundas Street Road Widening project (Northampton Boulevard to Guelph Line and Guelph Line to Kerns Road sections), including key milestones, forecasted quarterly expenditures, and the expected in-service date.
e) Does Burlington Hydro anticipate any further delays to the Dundas Street Road Widening project (Northampton Boulevard to Guelph Line and Guelph Line to Kerns Road sections)? If so, please provide details.
f) Please explain if the project delay will result in credits to customers refunding the ICM funding already collected from customers.

**Response:**

a) The revised in-service date for the Dundas Street Road Widening project (Northampton Boulevard to Guelph Line section) is driven by delays from the road authority.

b) The scope of work for the Northampton Boulevard to Guelph Line section has not changed due to the revised 2026 in-service date and includes the relocation of 43 poles and associated hardware (i.e. switches, pole mounted transformers, primary and secondary dips, services), 1.8km of overhead high voltage power lines and installation of 300m of underground primary cables for 3 circuits.

c) The factors that led to the change in the project costs are outlined below:

- Northampton Boulevard to Guelph Line: $4.09M (pre-filed evidence) to $3.79M (1-Staff-1)

  The project cost changed because the Region provided new data that affected the design of the project. The Region had initially designated a 60km per hour speed limit from Northampton Blvd to HWY 407, and changed it to a 80km per hour speed limit, which require BHI's poles to be set further back from the road. This change led to a constraint of space for an overhead line, so a portion of the relocation had to be converted from overhead to underground. This shifted more of the cost responsibility from BHI to the Region.

- Guelph Line to Kerns Rd.: $8.06M (pre-filed evidence) to $9.18M (1-Staff-1)

  The project cost changed because the Region revised the land profile data from the existing grade to a lower finished grade. This requires a taller and higher class of poles, as well as more anchors and guying to support them.

d) Please refer to Tables 1 (Guelph Line to Kerns Road) and Table 2 (Northampton Boulevard to Guelph Line) below for a project schedule and cost breakdown of each section.

**Table 1**

| Guelph Line to Kerns Road | | | | |
|---|---|---|---|---|
| Quarter | Key Milestones | Gross Capital Expenditures | Capital Contributions | Net Capital Expenditures |
| Q2 2025 | Cost sharing agreement with Region, finalize design | 12,181 | - | 12,181 |
| Q3 2025 | Material procurement, contract award, start of construction | 4,576,883 | - 2,198,739 | 2,378,144 |
| Q4 2025 | End of construction, energization | 4,589,064 | - 2,198,739 | 2,390,325 |
| | **2025 Total** | **9,178,128** | **- 4,397,477** | **4,780,651** |

**Table 2**

| Northampton Boulevard to Guelph Line | | | | |
|---|---|---|---|---|
| Quarter | Key Milestones | Gross Capital Expenditures | Capital Contributions | Net Capital Expenditures |
| Q1 2026 | Final design and approval, material procurement, start of construction | 1,896,804 | - 1,129,542 | 767,262 |
| Q2 2026 | End of construction, energization | 1,896,804 | - 1,129,542 | 767,262 |
| | **2026 Total** | **3,793,609** | **- 2,259,084** | **1,534,525** |

e) No, based on currently available information BHI does not anticipate any further delays to the Dundas Street Road Widening project (Northampton Boulevard to Guelph Line and Guelph Line to Kerns Road sections).

f) BHI will determine any potential credits owing to customers regarding the 2025 ICM project when 2025 actual results are available.

**Staff-99**

**Fixed asset - Capitalization**

**Ref 1: BHI_IRR_Staff_07242025, 2-Staff-27**

**Ref 2: APH (Accounting Procedures handbook Dec 2011), Article 410, Part a & b**

**Ref 3: Chapter 2 Filing Requirements for Electricity Distribution Rate Applications - 2025 Edition for 2026 Rate Applications, December 9, 2024, Section 2.2.2, p.18**

**Preamble:**

In Ref 1, Burlington Hydro states that its assets do not meet the definition of a qualifying asset, nor are the borrowing costs directly attributable to the acquisition, construction or production of that asset. It also states that the interest costs associated with the debt cannot be directly attributed to a specific asset. Burlington Hydro expenses interest on long-term debt in USoA 6605 which is not included in any components of revenue requirement.

**Question(s):**

a) Please confirm Burlington Hydro's practice of not capitalizing interests has been agreed upon by the external auditor and clarify whether Burlington Hydro has adopted this accounting policy in its previous cost of service applications under MIFRS. If not, please elaborate further.
b) Please provide the nature of USoA 6605 since it is not included in APH of Ref 2. Please update the evidence as applicable.

**Response:**

a) BHI confirms that its practice of not capitalizing interests has been agreed upon by its external auditor (refer to page 18 of BHI's 2024 Audited Financial Statements filed as Appendix G to Exhibit 1 of the Application). BHI has adopted this accounting policy in its previous cost of service applications under MIFRS.

b) BHI's response to 2-Staff-27 contained a typo related to the USoA. The answer should have stated that "BHI expenses interest on long-term debt in USoA 6005…" not USoA 6605. No update to the evidence is required.

**Staff-100**

**Revenue Impact – UsoA 1611**

**Ref 1: Chapter2Appendices_2BB_Service Life_07242025, 2BA**

**Ref 2: BHI_IRR_Staff_07242025, 2-Staff-28, Table 1**

Preamble:

In Ref 1 & 2, OEB staff has compiled Table (A) as below, showing the difference of revenue impact between Ref 1 and Ref 2.

Table (A): Comparation of Useful Lives

| **USoA 1611** | **2026 Test Year Capital Additions** | **2026 Test Year Accumulated Depreciation Additions** | **Amount included in Revenue requirement 2026 (RRWF)** |
|---|---|---|---|
| **Ref 1 (a)** | 611,120 | 1,019,118 | 1,154,982 |
| **Ref 2 (b)** | 5,308,751 | 3,429,987 | 594,438 |
| **Ref 2 (c)** | 5,308,751 | 5,211,156 | 247,621 |
| **Variance (b-a)** | **4,697,631** | **2,410,869** | **(560,544)** |
| **Variance (c-a)** | **4,697,631** | **4,192,038** | **(907,361)** |

**Question(s):**

a) Please explain the variance identified in the Table (A) above
b) Please show the calculation of the amount in Table 1 of Ref 2.
c) Please confirm whether USoA 1611 include both 5Y useful life assets and 10Y useful life assets.
    i. If c) is confirmed, please provide worksheet to show the calculation of the depreciation amount based on different useful lives in USoA 1611 and reconcile to Ref 1.

**Response:**

a) BHI's response to 2-Staff-28c) provided capital additions and accumulated depreciation on a cumulative basis for the affected CIS and GIS assets, instead of for USoA 1611 on a 2026 Test Year basis.

BHI provides the impact on a 2026 Test Year basis for UsoA 1611 in Table 1 below. BHI provides the impact using cumulative additions and depreciation for the GIS and CIS assets in Table 2 below, as provided in its response to 2-Staff-28.

The amount included in revenue requirement in 2026 of $1,154,982 in Table (A) above does not include the impact of deemed debt or the PILs impact of the change to deemed equity. BHI includes the impact to revenue requirement as a result of the change in deemed debt and PILs in both tables below (note in BHI's response to 2-Staff-28c) it did not include the impact to PILs in error). The impact to revenue requirement before PILs is $346,817 as identified in Table 1 of BHI's response to 2-Staff-28c).

The variance in revenue requirement, including deemed debt and PILs, using both methods of presentation is $371,425 i.e. revenue requirement in proposed rates is $371,425 higher than if BHI had depreciated its CIS and GIS assets using a 5-year useful life from 2022-2026.

**Table 1 – 2026 Test Year (OEB-Staff presentation)**

| USoA 1611 2026 Test Year | 2026 Test Year Additions | 2026 Test Year Deprn | Amount Included in Revenue Requirement | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | | 2026 Deprn | Deemed Equity | OEB-Staff-Calc | Deemed Debt | Rounding | 2-Staff-28 | PILS | Total |
| Ref 1a) - Currently in Proposed Rates | $611,120 | $1,019,118 | $1,019,118 | $135,864 | $1,154,982 | $97,992 | $74 | $1,253,048 | $48,985 | $1,302,033 |
| CIS and GIS at 5 yrs | $611,120 | $789,842 | $789,842 | $67,615 | $857,457 | $48,767 | $7 | $906,231 | $24,377 | $930,609 |
| **Difference** | **$0** | **$229,276** | **$229,276** | **$68,249** | **$297,525** | **$49,225** | **$67** | **$346,817** | **$24,608** | **$371,425** |

**Table 2 – 2026 Cumulative Additions and Depreciation (2-Staff-28 c) presentation)**

| CIS/GIS 2026 Cumulative | 2026 Cumul. Additions | 2026 Accum Deprn | Amount Included in Revenue Requirement | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | | 2026 Deprn | Deemed Equity | OEB-Staff-Calc | Deemed Debt | Rounding | 2-Staff-28 | PILS | Total |
| CIS and GIS Currently in Proposed Rates | $5,308,750 | $3,429,987 | $463,583 | $75,980 | $539,563 | $54,801 | $74 | $594,438 | $27,394 | $621,832 |
| CIS and GIS at 5 yrs | $5,308,750 | $5,211,158 | $234,307 | $7,731 | $242,038 | $5,576 | $7 | $247,621 | $2,786 | $250,407 |
| **Difference** | **$0** | **($1,781,171)** | **$229,276** | **$68,249** | **$297,525** | **$49,225** | **$67** | **$346,817** | **$24,608** | **$371,425** |

b) BHI provides a detailed calculation of the amount in Table 1 of Ref 2 (2-Staff-28) as CQ_Attachment_Staff-100, Tab “Staff-100b) and 100c)”. The amounts included in BHI’s response to 2-Staff-28 are highlighted in green. A summary calculation is also provided in Tab “Staff-100a) Calculation”.

c) BHI confirms that USoA 1611 includes both 5Y useful life assets and 10Y useful life assets.

   i. BHI provides a worksheet to show the calculation of the depreciation amount based on different useful lives in USoA 1611 as CQ_Attachment_Staff-100, Tab “Staff-100b) and 100c)”. Column Q represents the depreciation included in rates for USoA 1611. The amounts highlighted in orange balance to OEB Appendix 2-BA (Ref 1).

**Staff-101**

**ICM**

**Ref 1: Chapter2Appendices_2BB_Service Life_07242025, 2BA**

**Ref 2: Attachment 2_2025 ICM Model_BHI_20250124**

**Preamble:**

In Ref 1, OEB staff notes Burlington Hydro moved total ICM assets ($4.7M) from 2025 to 2026 capital base.

| | 2025 | | 2026 | |
|---|---|---|---|---|
| | **Cost (ICM)** | **Accumulated Depreciation** | **Cost (ICM)** | **Accumulated Depreciation** |
| **1830 - Poles, Towers & Fixtures** | -2,516,898 | 31,461 | 2,516,898 | -62,922 |
| **1835 - Overhead Conductors & Devices** | -1,370,603 | 23,137 | 1,370,603 | -46,274 |
| **1855 - Services (Overhead & Underground)** | -874,842 | 9,713 | 874,842 | -18,347 |
| **Total** | -4,762,343 | 63,772 | 4,762,343 | -127,544 |

**Question(s):**

a) Please explain the rationale of this practice observed by OEB staff.
b) Please confirm whether 2025 capital additions (column E) in Ref 1 includes this $4.7M ICM cost.
c) Please confirm whether 2026 capital additions (column E) in Ref 1 includes this $4.7M ICM cost.
d) Please confirm there is no double counting of this $4.7M ICM in both 2025 and 2026.

**Response:**

a) The 2025 capital additions (column E) in Ref 1 included additions related to the approved 2025 ICM project. BHI removed these costs from the Closing Balance through a reduction in the ICM column (column G) to reflect that the additions are not yet approved to be added into rate base. BHI is proposing to include these capital additions in rate base through an addition to the ICM column (column G) in the 2026 Test Year. BHI applied the same rationale to Accumulated Depreciation. This is consistent with BHI's approach in its 2021 Cost of Service application[1].

b) BHI confirms the 2025 capital additions (column E) in Ref 1 include the $4.7M ICM cost.

c) The 2026 capital additions (column E) in Ref 1 do not include the $4.7M ICM cost.

d) BHI confirms there is no double counting of the $4.7M ICM in either 2025 or 2026.

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[1] EB-2020-0007, App.2-BA_Fixed Asset Cont

**Staff-102**

**Vehicles**

**Ref 1: Response to 2-Staff-23**

**Ref 2: IR_Attachment_2-Staff-23d_BHI_07242025**

**Question(s):**

a) Is Burlington Hydro proposing to repair or replace single bucket truck T22 in the 2026 Test Year? If Burlington Hydro is replacing the vehicle, please state the need for replacement as the Matrix Score value is 16.

**Response:**

a) BHI incorrectly identified that the single bucket truck T22 would undergo a “repair” instead of a “modification” in the 2026 Test Year for $51,000. This expenditure represents modifying truck T22 with an electronic Power Take Off (ePTO), which will enable it to operate more efficiently and sustainably. Single bucket truck T22 is not being replaced in the 2026 Test Year.

**Staff-103**

**Buildings**

**Ref 1: Exhibit 2 – Appendix O**

**Ref 2: Response to 2-Staff-24**

**Question(s):**

a) Please specify what projects from the 2021 Building Condition Assessment will be completed during the forecast period. Please provide the updated costs associated with each project if available to Burlington Hydro.

b) Please provide the costs of the North and South parking lot projects individually.

c) Please provide the 'Needs Assessment' for the projects referenced in 2-Staff-24 part a.

**Response:**

a) BHI provides a list of projects from the 2021 Building Condition Assessment, as well as the 2024 Asset Condition Assessment and 2024 Security Assessment Report, that will be completed during the forecast period in Table 1 below. There is no change to the costs provided in BHI's response to 2-Staff-24 a).

**Table 1**

| Program | 2026 Test Year | 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|---|---|
| 1340 Brant St. Replacements | $275,400 | $239,200 | $265,250 | $162,300 | $165,600 |
| [redacted] | $234,600 | $0 | $0 | $0 | $0 |
| North Parking lot | $0 | $124,800 | $127,320 | $0 | $0 |
| HVAC System | $32,640 | $33,280 | $33,952 | $34,624 | $17,664 |
| **Total Projects from the 2021 Building Assessment** | **$542,640** | **$397,280** | **$426,522** | **$196,924** | **$183,264** |
| 1328 Brant St. MS building | $10,200 | $10,400 | $10,610 | $10,820 | $11,040 |
| Distribution Stations | $24,480 | $24,960 | $31,830 | $32,460 | $33,120 |
| **Total Projects from the 2024 Asset Condition Assessment** | **$34,680** | **$35,360** | **$42,440** | **$43,280** | **$44,160** |
| [redacted] | $66,300 | $10,400 | $10,610 | $10,820 | $11,040 |
| **Total Projects from the 2024 Security Assessment Report** | **$66,300** | **$10,400** | **$10,610** | **$10,820** | **$11,040** |
| Remaining Projects | $227,460 | $101,920 | $103,978 | $84,396 | $59,616 |
| **Total Projects** | **$871,080** | **$544,960** | **$583,550** | **$335,420** | **$298,080** |

b) BHI provides the costs of the North and South parking lot projects individually in Table 1 below.

**Table 1**

| Description | 2026 | 2027 | 2028 | Total |
|---|---|---|---|---|
| South Parking lot | $127,500 | $0 | $0 | **$127,500** |
| North Parking lot | $0 | $124,800 | $127,320 | **$252,120** |
| **Total** | **$127,500** | **$124,800** | **$127,320** | **$379,620** |

c) BHI provides the needs assessment for the projects referenced in 2-Staff-24 a) as follows:

South Parking lot

The expansion of the visitor parking lot is driven by the need to accommodate increased visitors, contractors/vendors, and additional staff to BHI's head office. BHI updated its internal policy to require all non-employee personnel to use the visitor parking lot and the South entrance to help maintain appropriate safety and security protocols.

HVAC System

Expenditures above the amounts identified in the 2021 Building Condition Assessment are based on condition (one unit has failed), age (units identified for replacement are beyond their expected service lives) and ongoing maintenance and repair costs. To pace these expenditures, BHI included replacement of two HVAC units each year in the forecast period.

1340 Brant St. Upgrades

This investment is based on the need to add new office space and workstations to accommodate planned increases in Full-Time Equivalents (FTEs), per Section 4.3.1.1 of Exhibit 4.

**Staff-104**

**Subdivisions**

**Ref 1: Response to 2-Staff-22**

**Question(s):**

a) Please provide the actual and forecasted number of buybacks Burlington Hydro assumed each year from 2021 to 2025.

**Response:**

a) BHI provides the actual and forecasted number of buybacks (units) it assumed each year from 2021 to 2025 in Table 1 below.

**Table 1**

| Subdivision Buybacks (Units) | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|
| Forecast (EB-2020-0007) | 300 | 300 | 300 | 300 | 300 |
| Actual* | 0 | 0 | 0 | 170 | 411 |

*2025 = forecast

**Staff-105**

**Ref: 3-Staff-36**

Question(s):

a) Can you explain how you leveraged these sources and demonstrate the workings of how 15% was calculated?

**Response:**

a) The 15% figure is based on judgement and is not the result of a specific calculation. Data from the NRCan National Energy Use Database is summarized in Table 1 below and shows approximately 10% of the increase in home heating stock in 2022 is due to heat pumps. Discussion of home heating from the Burlington Distribution System Sustainability Plan and the IESO's Pathways to Decarbonization report indicate heat pump adoption is expected to increase, and as such a 50% increase over historic adoption (for a total home heating conversion rate of 15%) was incorporated into the load forecast.

**Table 1**

| Heating Stock (thousands) | | | | | | | |
|---|---|---|---|---|---|---|---|
| | | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 |
| Total Heating Stock | Total | 5,575 | 5,651 | 5,734 | 5,831 | 5,936 | 6,034 |
| | Yearly Increase | | 76 | 83 | 98 | 105 | 98 |
| Heat Pump | Total | 77.9 | 84.9 | 91.9 | 101.4 | 111.3 | 121.3 |
| | Yearly Increase | | 7.0 | 7.0 | 9.5 | 9.9 | 10.1 |
| Heat Pump % of Yearly Increase | | | 9.2% | 8.5% | 9.7% | 9.4% | 10.3% |

## Staff-106

**Ref: 4-Staff-40 (b,c,d)**

Question(s):

a) Please explain how 261 service connection requests in 2025 to date are forecasted to increase from 261 to 1,091.
b) Please confirm if there has been a trend in historical actuals for the number of service connection requests to increase disproportionately in the latter half of previous years.
c) In response d(iii), Table 4, Burlington Hydro provides the number of OT hours from 2024 to 2025 actuals. Please explain why there is an inverse relationship between OT hours for the Engineering Technician role and the rise in customer service requests.

**Response:**

BHI identified an error in the forecasted number of connections and connection requests in the following IR responses, and has refiled corrected versions of these IR responses as CQ_Attachment_Staff-106:

- 4-Staff-40
- 4-Staff-42
- 4-Staff-51
- 2-Intervenor-34

a) Forecasted 2025 connection requests were based on a linear regression analysis using 2021-2024 actuals (per 4-Staff-42) and did not incorporate 2025 YTD results.

b) BHI has not analyzed the trend in historical actuals for the number of service connection requests in the first half vs. second half of previous years. However, BHI received 93 requests in the month of July 2025 as compared to an average of 44 requests per month in the first six months of 2025.

c) Customer connection service requests vary considerably in terms of scope, complexity, level of customer interaction required and time to connection. The OT hours, therefore, do not have a direct correlation with the number of connection requests received by BHI during the subject period.

**Staff-107**

**Ref: 4-Staff-42**

Question(s):

a) Please provide an explanation for why the Engineering Clerk and Locate Clerk have not logged any OT hours, despite the increase in actual and forecasted locate requests indicated in Table 2.

**Response:**

a) Overtime work is voluntary for unionized staff including for the Engineering Clerk and Locate Clerk. To ensure compliance with Ontario One Call regulations and avoid the risk of administrative penalties,[1] the increased locates workload has been managed by reprioritizing and deferring other engineering tasks carried about by the Engineering Clerk and Locates clerk, and by incurring overtime at the management level to supplement the capacity of the clerks (e.g. complete locates overflow work that the clerks cannot execute within normal business hours, and complete other clerical engineering tasks such as responding to customer inquiries related to service connections and upgrades, scheduling service appointments with customers, processing internal engineering documents, coordinating permits, site plan, zoning and committee of adjustment processing, and responding to third-party (i.e. Electrical Safety Authority) inquiries.

[1] These regulations impose strict timeline requirements on LDCs to respond to standard locates within 5 business day and complex/multi-address locates within 10 business days in order.

**Staff-108**

**Ref: 4-Staff-44(c)**

Question(s):

a) In response c to the above staff interrogatory, Burlington Hydro outlined the reasoning for the increased workload for the Communications Advisor role. Please provide figures for the growth in Burlington Hydro's social media following, and clarify how a rise in social media following results in the need for a higher volume of content to be created.

**Response:**

a) BHI has experienced a sustained increase in its social media following across all major platforms. As of August 2025, Burlington Hydro's combined follower count has grown by 31.6% compared to 2022. This includes:

- X: Growth of 24% driven by updates on power outages and restoration efforts.
- LinkedIn: Growth of 87% driven by expanded community engagement, participation in community events and corporate updates such as infrastructure investments.
- Instagram: Growth of 212%, supported by visual storytelling and safety campaigns.

This growth is driven by a shift in how BHI's customers and stakeholders prefer to receive information – as they increasingly look for digital-first communications. This can be seen in the results of BHI's 2024 Customer Service Survey in which growth in customers reaching out on digital channels grew by 23% while inquiries via telephone declined by 9%.

A larger audience requires more frequent and varied content to maintain relevance and increase visibility to ensure customers receive information about BHI and its services. BHI customers place high value on content that is both informative and timely such as updates on power outages, restoration timelines, energy-saving tips, emergency preparedness and safety reminders. Educational posts about new programs, billing options, and sustainability initiatives help customers make informed choices. Visual storytelling, such as behind-the-scenes looks at field crews or infographics explaining complex topics, further engages the community and builds trust. BHI continues to review and expand its posting frequency, and diversify its content to meet these expectations.

Operating across multiple corporate accounts, the Communications Advisor must also customize messaging to different platforms and audiences, while maintaining a consistent brand voice. This has resulted in an increase in content creation activity of 30.4% from 2022 to 2024 (the last full year of data).

Overall, the growth in BHI's social media following has led to a proportional increase in the Communication Advisor's efforts to develop a higher volume of timely, relevant and targeted content across its four corporate social media channels.

**Staff-109**

**Ref: 4-Staff-45(a)**

Question(s):

a) Burlington Hydro states that financial planning, regulatory compliance and capital tracking related responsibilities are currently dispersed among various roles in the Finance department, and that the utility does not track OT hours for these positions:

- Controller
- Financial Accountant,
- Financial Analyst
- Accountant, Financial and Regulatory
- a temporary Co-Op student

Please confirm whether any OT hours have been assigned to the above roles (aside from the 65-1,300 hours logged by the co-op student) in regard to the financial planning, regulatory compliance, and capital tracking functions that the proposed Financial Analyst would assume.

**Response:**

a) BHI confirms that OT hours have been assigned to all of the roles identified above (aside from the 650-1,300 hours logged by the co-op student) in regard to the financial planning, regulatory compliance, and capital tracking functions that the proposed Financial Analyst would assume.

**Staff-110**

**Ref: 4-Staff-50 (b)**

Question(s):

a) In its response, Burlington Hydro indicated it had redistributed key responsibilities among the current team (three manager-level Distribution Engineers and the Vice-President, Engineering Services & Network Operations) and listed the specific responsibilities taken on by the other staff during the vacancy. Where possible, please provide OT hours for each role indicated above associated with the specific responsibilities outlined in the response.

**Response:**

a) BHI does not track overtime hours for the three manager-level Distribution Engineers and the Vice-President, Engineering Services & Network Operations.

**Staff-111**

**Ref: 4-Staff-57**

Question(s):

a) In its response to the above interrogatory, Burlington Hydro estimated that 15 FTEs have had work assigned which is associated with OEB policy consultations and initiatives, but indicated that the requested information is too granular to provide an accurate response. Please provide the number of OT hours for these 15 FTEs have logged each year from 2021 to 2024 and YTD 2025.

**Response:**

a) The number of OT hours from 2021 to 2024 and YTD 2025 for these 15 FTEs is unavailable. These 15 FTEs are primarily non-union positions for which BHI does not log unpaid overtime.

**Staff-112**

**Ref: 4-Staff-63(d)**

Question(s):

a) Burlington Hydro indicated that the absence of a dedicated Engineering Supervisor, Energy Transition, some of the tasks identified in part (a) of its response are distributed across existing portfolios within the engineering department. Please provide an overview of which tasks were assigned to which department or role.

**Response:**

a) BHI identifies the tasks that are distributed across existing portfolios within the engineering department as follows:

- Strategic Planning and Integration: System Planning and Engineering Design groups
- Project Execution: Engineering Design and Customer Connections, Key Accounts groups
- Stakeholder Engagement: Engineering Design and Customer Connections, Key Accounts groups
- Policy and Regulatory Compliance: Engineering Design and Customer Connections, Key Accounts groups

The remaining tasks require resourcing in the form of the Supervisor, Energy Transition Integration and include centralized project oversight, technical leadership, data and performance monitoring, and team leadership and development.

**Staff-113**

**Ref: 4-Staff-66**

Question:

a) In response b, Burlington hydro indicates that effectively addressing employee turnover is a critical component of this role, citing a high average turnover rate. However, in its response to 4-Staff-39 (responses to b-c-d, Table 1), Burlington Hydro provides updated turnover figures for 2025, indicating that employee turnover continues to trend downward. Please reconcile the stated need for the HR role in the context of declining turnover.

**Response:**

a) BHI has consistently experienced a double-digit average turnover rate over a period exceeding five years. It has experienced a wave of retirements and unwanted turnover resulting in over 75% of its workforce turning over (refer to page 221 of Exhibit 4).

   Although turnover has recently trended downward, it is still significant and disruptive to the organization (see Table 1 of 4-Staff-39). Further, the declining trend is not necessarily indicative of the future. To maintain turnover levels sustainable in a labour market that is expected to be increasingly competitive due to labour shortages and growth, BHI must take proactive steps to manage turnover risk and impact to the organization, including enhancing processes, procedures and HR programs such as succession planning, workforce planning and training to ensure knowledge transfer takes place prior to turnover occurring.

   Delivering these proactive HR initiatives effectively while also addressing other incremental requirements in this portfolio, requires the support of another HR professional. Other requirements in this portfolio driving the need for an additional resource include the proposed addition of 14 FTE in 2026, as identified in Exhibit 1 at pp. 40-42 and Exhibit 4 at pp. 193-197.

   Managing a larger workforce entails higher work volumes related to position analysis, workforce planning, employee engagement, performance management, recruitment and retention activities, training and development programs, employee relations and issues resolutions, and change management, particularly in the context of technological advancements and the shift to remote work as a result of the COVID-19 pandemic.

**Staff-114**

**PILs Model**

**Ref 1: BHI_IRR_Staff_07242025, 6-Staff-76, Table 2**

**Ref 2: Attachment_2026 PILs Workform_BHI_07242025, B8_Sch8_CCA Bridge**

**Ref 3: Attachment_OEB_Chapter2Appendices_BHI_07242025, 2BA, Y2025**

Preamble:

Per Ref 1, 2 & 3, OEB staff has reconciled 2025 capital additions between PILs model (Schedule 8) and Appendix 2BA (before CWIP addition and excluding land), which shows the variance from Ref 1.

Table (1): Reconciliation of Capital Additions between PILs (Sch8) & 2BA

| | **Ref 1 (a)** | **OEB Staff Notes** |
|---|---|---|
| **Capital Additions per Appendix 2-BA** | 17,903,861 | There is variance of $203,215 from Ref 3 since Burlington Hydro included CWIP amount. |
| **Capital Additions per the PILs Model** | 12,715,489 | There is variance of ($140,700) from Ref 2 since Burlington Hydro included column H adjustment |

**Question(s):**

a) Please confirm OEB staff's observation.
b) Please explain, reconcile and update the 2025 capital addition amount between Ref 2 and Ref 3

**Response:**

a) BHI confirms that the capital additions per Appendix 2-BA identified in Table 2 in 6-Staff-76 were $17,903,861 and should have been $17,700,646 to incorporate WIP of $203,215.

   BHI confirms that the capital additions per the PILS model identified in Table 2 in 6-Staff-76 of $12,715,489 included the column H adjustment of ($140,700).

b) BHI provides an updated Table in response to 6-Staff-78 below as Table 1. BHI files an updated PILS Model as Attachment_2026_PILS_Workform_BHI_08112025 to move the WIP of $203,215 from column E to Column H. There is no impact to the PILS calculation.

**Table 1 – Revised Table 2 (6-Staff-78)**

| Description - Clarification Questions (Staff-114) | 2025 | 2026 |
|---|---|---|
| **Capital Expenditures per Appendix 2-AB** | **$17,903,861** | **$24,870,805** |
| Add/(Deduct) WIP | -$203,215 | $46,195 |
| **Capital Additions per Appendix 2-BA (Ref 3)** | **$17,700,646** | **$24,917,000** |
| Deduct: Capitalized Overhead in 2-BA deducted for tax purposes | -$289,483 | -$289,483 |
| Deduct: SR&ED Capitalized in 2-BA deducted for tax purposes | -$136,546 | -$136,546 |
| (Deduct)/Add: Adjustment to Class 47 (ICM Dundas Road Widening) | -$4,762,343 | $4,762,343 |
| **Capital Additions including CCRA refund of $140,700** | **$12,512,274** | **$29,253,314** |
| Add: HONI CCRA Refund captured in column H of PILS model | $140,700 | 0 |
| **Capital Additions per PILS model (column E) (Ref 2)** | **$12,652,974** | **$29,253,314** |

**Staff-115**

**Accelerated CCA & Smoothing Mechanism**

**Ref 1: BHI_IRR_Staff_07242025, 6-Staff-78, Table 2**

**Question(s):**

a) Please complete the Table below (compiled by OEB staff) based on forecast CCA amount from 2028 to 2030.

| | 2028 Forecast | 2029 Forecast | 2030 Forecast | **Cumulative Total** |
|---|---|---|---|---|
| CCA Legacy (no AIIP) (a) | | | | |
| CCA Bill C-97 (with AIIP) (b) | | | | |
| CCA Difference (c=b-a) | | | | d |
| **Take 1/5 of Difference** (e=d/5) | | | | |
| **Income tax** (f=e*26.5%) | | | | |
| **Gross up** (g=f/73.5%) | | | | |
| **2026 PILs expense** (h) – Ref 1 | 925,602 | | | |
| **Total Revenue Requirement** (g+h) | | | | |

**Response:**

a) BHI provides the completed table as Table 1 below.

**Table 1**

| Description | 2028 Forecast | 2029 Forecast | 2030 Forecast | Cumulative Total |
|---|---|---|---|---|
| CCA Legacy (no AIIP) (a) | $11,998,791 | $13,348,517 | $13,437,396 | **$38,784,703** |
| CCA Bill C-97 (with AIIP) (b) | $13,495,866 | $14,139,971 | $13,542,520 | **$41,178,357** |
| CCA Difference (c=b-a) | $1,497,075 | $791,454 | $105,124 | **$2,393,654** |
| **Take 1/5 of Difference** (e=d/5) | $478,731 | | | |
| **Income tax** (f=e*26.5%) | $126,864 | | | |
| **Gross up (g=f/73.5%)** | **$172,604** | | | |
| **2026 PILs expense** (h) – Ref 1 | $925,602 | | | |
| **Total Revenue Requirement** | **$1,098,206** | | | |

**Staff-116**

**DVA Continuity**

**Ref 1: Attachment_DVA_Continuity_Schedule_BHI_07242025**

**Question(s):**

a) Please confirm the most recent OEB prescribed interest rate has been used in calculating the carrying charges in Ref 1.

**Response:**

a) BHI has incorporated the OEB prescribed interest rates up to Q2 2025 in calculating the carrying charges in Ref 1.

**Staff-117**

**Group 1**

**Ref 1: BHI_IRR_Staff_07242025, 9-Staff-82**

Preamble:

Per Ref 1, Burlington Hydro states that it is currently still in the process of verifying the accuracy of the automated settlement calculations of which the targeting completion is by the end of 2025 and hasn't identified any material adjustments to Group 1 accounts due to the new process up to this point.

**Question(s):**

a) Please confirm whether Burlington Hydro has identified any material adjustment in the IESO settlements and Group 1 DVAs.

**Response:**

a) BHI has not identified any material adjustments in the IESO settlements and Group 1 DVAs due to the new process up to this point.

**Staff-118**

**Customer choice**

**Ref 1: BHI_IRR_Staff_07242025, 9-Staff-90**

Preamble:

Per Ref 1, Burlington Hydro proposes to keep the Customer Choice Account open in case it incurs any incremental costs directly attributable to future code amendments made in response to
Customer Choice initiatives.

OEB staff notes Burlington Hydro has already included the forecast amount up to December 2025 and the implementation starts from 2020 which has been 5 years.

**Question(s):**

a) Please provide the thought on discontinuing the account, given that the account was established to record the incremental costs associated with the customer billing choice initiative in 2020.

**Response:**

a) BHI withdraws its request to continue the Customer Choice Account.

**Staff-119**

**Impacts Arising from the COVID-19 Emergency**

**Ref 1: BHI_IRR_Staff_07242025, 9-Staff-93, Table 1**

OEB staff has complied the following Table (B) showing the Means Test calculation:

| Item | 2020 | 2021 | Calculation of 2021 ROE |
|---|---|---|---|
| **OEB approved ROE % (Ref 1)** | 9.36% | 8.68% | 9.36% (Jan~Apr)/12*4 + 8.34%(May~Dec)/12*8 =**8.68%** |
| **Less: 300bps (Ref 1)** | 3.00% | 3.00% | |
| **Allowed ROE % (Ref 1)** | 6.36% | 5.68% | 8.68% - 3.00% = **5.68%** |
| **Achieved ROE % (Ref 1)** | 1.49% | 6.44% | 4.57%(Jan~Apr)/12*4 + 7.38%(May~Dec)/12*8 =**6.44%** |
| **Means Tests** | **Pass** | **Fail** | |

OEB Staff notes that the Means Tests for entire 2021 failed on weighted average basis per Table (B) above.

**Question(s):**

a) Please confirm OEB staff's observation in Table (B) or revise the table as applicable.
b) If confirmed, please update the Account 1509 balance by excluding the 2021 amount.

**Response:**

a) BHI is not able to confirm OEB's staff's observation in Table B. BHI's rate setting period during COVID was from May 1 to Apr 30. BHI's rate structure changed May 1, 2021. As such BHI does not think it is appropriate to take the average of the ROE from two different rate setting periods to determine the deemed and actual ROE for the threshold test. Each rate-setting period should be assessed individually.

BHI respectfully disagrees with OEB staff's methodology used in Table B for the following reasons:

<u>OEB approved ROE %</u>

OEB staff's calculation uses a weighted average of the OEB approved ROEs for 2021. However, based on BHI's interpretation of the OEB's COVID-19 Deferral Account Report (issued June 17, 2021), specifically Section 4.2.1, the means test is to be applied by comparing the achieved ROE to the OEB-approved ROE less 300 basis points, as applicable to the claim period.

*"The OEB will apply a means test to recoveries in the Account based on achieved ROE compared to a utility's OEB-approved ROE less 300 basis points."*

The report does not reference or suggest the use of a weighted average of the OEB-approved ROEs for split-year calculations. Therefore, BHI applied the OEB-approved ROE applicable for the relevant periods (i.e., January to April 2021) during which the COVID-19 amounts were incurred and are being claimed.

<u>Achieved ROE %</u>

Similarly, BHI does not agree with the approach of using a full-year weighted average achieved ROE that includes the May to December 2021 period. As noted in its response to 9-Staff-93, no amounts related to May–December 2021 are being claimed under the COVID-19 deferral account.

Calculating the weighted average achieved ROE 2021 by including the period (May to December) which is not subject to recovery creates a mismatch between the basis of the means test and the actual claim period.

b) Not applicable.

**Staff-120**

**Capital Additions Dundas Street Road Widening Project - Revenue Requirement**

**Differential Variance Account (CVA1)**

**Ref 1: BHI_IRR_Staff_07242025, 9-Staff-94, Figure 1**

**Ref 2: Exhibit 9, section 9.1.11, Table 27**

Preamble:

Per Ref 1, Burlington Hydro states that the increase of 510K was reduced by a decrease in 2020 resulting in a total expenditure increase was 225K over 2020-2021. It also states that $3,035,948 represents the amount tracked through CVA1.

**Question(s):**

a) Please confirm the $225k decrease mentioned above has been applied to the actual project cost.
   i. If confirmed, please update the Actual Additions in Ref 2 to reflect the decrease of $225k
   ii. If not confirmed, please explain why not

**Response:**

a) The $225K in Ref 1 is an increase, not a decrease. The 2020 Bridge Year forecast decreased and the 2021 Test Year forecast increased for a net forecasted increase of $225K over the 2020-21 period. BHI provides the changes for forecasted expenditures from its application to its interrogatory responses from its 2021 Cost of Service application in Table 1 below.

**Table 1**

| Dundas St. Road Widening | 2020 Bridge Year | 2021 Test Year | Total |
|---|---|---|---|
| Application (EB-2020-0007) | 350,194 | 2,526,183 | **2,876,378** |
| Interrogatory responses (EB-2020-0007) | 65,275 | 3,035,948 | **3,101,223** |
| Change | **- 284,919** | **509,765** | **224,845** |

i. The forecasted decrease of ($284,919) in the 2020 bridge year was reflected in Appendix 2-AA of the Chapter 2 Appendices filed with BHI's settlement proposal[1]. 2020 actual expenditures are not reflected in the Actual Additions in Ref 2 because CVA1 tracked budgeted vs. actual capital additions in 2021 only. The increase of $509,765 in the 2021 Test Year was a forecast. Actual incurred capital expenditures for 2021 are included in the Actual Additions of $517,315 in Ref 2.

ii. Please see response to part a i) above.

[1] EB-2020-0007, Attachment_Main_OEB_Chapter2Appendices_BHI_Revised, February 1, 2021

**ED-CQ-1**

**Reference: 2-Intervenor-33 (b) and (d)**

Question(s):

Exhibit 2-Intervenor-33 (b) and (d) indicate that BHI does not charge residential customers to upgrade their service up to 200 amps. Please confirm whether this includes there being no charges for (a) the connection/disconnection needed to replace the panel and (b) the cost to upgrade the conductor serving the home (where applicable). If there are charges for those amounts, please let us know what they are.

**Response:**

BHI confirms it does not charge for (a) the connection/disconnection needed to replace the panel and (b) the cost to upgrade the conductor serving the home (where applicable) when upgrading a service to 200 amps as long as the scope of work falls within BHI's defined Basic Connection.

**<u>ED-CQ-2</u>**

**Reference: 2-Intervenor-33 (f)**

Question(s):

Exhibit 2-Intervenor-33 (f) indicates that "[r]esidential service upgrades are completed in an average of 16 weeks for underground service and 8 weeks for overhead service." That seems like a very long time to make a customer wait who wishes to upgrade their service panel, particularly in cases where all the utility needs to do is cut off the power and reconnect the power. Please explain why the wait is so long.

**Response:**

The majority of customer service upgrade requests involve more than the disconnect and reconnect of power associated with the simple changeout of a service panel or fuses on the panel. For the majority of customer service upgrade requests, BHI has to ensure that the new (upgraded) service meets the current safety standards as per Reg.22/O4 requirements and approved equipment (such as service conductor) meets customer requirements. This requires a site inspection by a qualified design/services technician, assessment of the size and condition of connection assets both on the customer and BHI side of the demarcation point, preparation of scope of work for BHI and the customer, design documents, locates, applicable permit approvals, followed by an offer to connect. Therefore, appointments are scheduled to ensure that all required conditions are met before the new service can be energized. This also allows the customer to prepare their equipment to receive the new service from BHI and obtain the necessary approvals from the safety authority (ESA).

For upgrades involving underground service, the timeline is generally longer as the work has to be coordinated with contractors specialized in civil construction works in addition to the electrical work by BHI.

Where it is determined that the existing BHI infrastructure can accommodate the service upgrade, BHI is typically able to accommodate the customer with a shorter timeframe for disconnection and reconnection of service.

**ED-CQ-3**

**Reference: 2-Intervenor-34**

Question(s):

Please provide a table and an explanation to reconcile Table 1 and Table 2 in 2-Intervenor-34. Those tables show a large disparity between new connections and connection requests.

**Response:**

Note: BHI identified an error in the forecasted number of connections and connection requests in the following IR responses, and has refiled corrected versions of these IR responses as CQ_Attachment_Staff-106:

- 4-Staff-40
- 4-Staff-42
- 4-Staff-51
- 2-Intervenor-34

BHI provides a response to ED-CQ-3 based on the corrected Tables 1 and 2 in 2-Intervenor-34.

Table 1 in 2-Intervenor-34 included forecasted new connections, whereas Table 2 in 2-Intervenor-34 included forecasted connection requests. Forecasted connection requests are higher than forecasted new connections because i) they include requests for upgrades which are not considered new connections, ii) they include MTSA connection requests in 2026 and 2027 that will not result in new connections until 2028 and 2029 because a system expansion is required, and iii) they include requests for connection where the customer decides not to proceed with the connection. BHI provides a reconciliation between the corrected versions of Table 1 and Table 2 in 2-Intervenor-34 in Table 1 below.

**Table 1**

| Forecast | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|---|---|---|
| New Connections (2-Intervenor-34 a), Table 1) | 524 | 612 | 700 | 1,253 | 1,341 | |
| Connection Requests (2-Intervenor-34 c), Table 2) | | 1,783 | 1,941 | 2,099 | 2,257 | 2,415 |
| **Difference** | | **1,172** | **1,241** | **846** | **916** | |
| Connection Requests for Upgrades | | 686 | 743 | 765 | 788 | |
| Major Transit System Area (MTSA) Connection Requests | | 465 | 465 | - | - | |
| Connection Requested but Customer not Proceeding | | 21 | 33 | 81 | 128 | |

**ED-CQ-4**

**Reference: 2-Intervenor-36 (f)**

Question(s):

Is BHI willing to assist customers in the ways outlined in 2-Intervenor-36 (f)?

**Response:**

Yes, BHI is willing to assist customers in the ways outlined in 2-Intervenor-36 f). BHI's ability to assist customers in all of these ways is dependent on, but not limited to, the following factors:

- Resource constraints – assisting these customers is contingent on BHI implementing its workforce management strategy of upskilling existing employees and creating new positions to ensure it has the capacity and knowledge to assist and educate customers;
- Investing in foundational technologies such as ADMS and smart field devices to modernize grid management capabilities in response to increased demand, electrification, and DER penetration;
- Distribution system factors such as available capacity;
- LDC roles and responsibilities within Stream 2 of the IESO's eDSM framework;
- Availability of incentives and eligibility criteria;
- Regulatory policy and guidelines; and
- EV uptake and (multi-unit residential building owner) customer interest.

**ED-CQ-5**

**Reference: 2-Intervenor-37**

Question(s):

2-Intervenor-37 indicates as follows: “c) BHI has not yet made a determination on whether all new AMI 2.0 meters will be bidirectional or not. Having all meters as bi-directional carries higher maintenance and reverification costs in the future. All new AMI 2.0 meters will have the capability of being programmed and sealed as bi-directional.”

a) Please elaborate on this response.

b) Why is there a higher cost to maintain and verify bi-directional meters?

c) Does the response mean that an AMI 2.0 meter could be installed without bi-directional capability but later updated to add that functionality without fully replacing it?

d) Can these capabilities be added via a firmware update?

e) All of the AMI 2.0 meters to be installed by Toronto Hydro will be bi-directional. Why is BHI potentially proposing something different?

**Response:**

a) BHI is still evaluating new meters and their performance and has not made a final decision on the features and programming parameters of new meters. Having all meters as bi-directional could impact the data backhaul and contribute to mesh network data volumes.

b) There are higher costs from Measurement Canada accredited test facilities for sealing a bi-directional meter since they have to run the same tests twice, once in each direction, resulting in added labour for the testing.

c) Yes, AMI 2.0 meters could be installed without bi-directional capability but later updated to add that functionality without fully replacing the meter.

d) Yes, certain capabilities including bi-directional channels can be programmed or enabled via an over the air firmware update.

e) Please see BHI’s response to part a).

**ED-CQ-6**

**Reference: 2-Intervenor-40 (a)**

Question(s):

Why does BHI disagree with all of the recommendations set out in the report found at 2-Intervenor-40(a)?

**Response:**

The Energy Storage Feasibility Study (the Study) provided recommended next steps should BHI proceed with the deployment of the Battery Energy Storage System (BESS). The site considered in the Study (Fairview MS) is currently an active substation with customers connected to it. As such, due to operational factors, BHI is not able to proceed with the deployment of the BESS until customers have been converted to a 27.6kV supply and the substation has been decommissioned.

The intent of the study was to explore the feasibility, benefits, and potential challenges of integrating a BESS into BHI's grid infrastructure. BHI will revisit this study and assess the recommended next steps if/when it is ready to proceed with a BESS deployment at the Fairview MS, or elsewhere within its service territory.

## ED-CQ-7

**Reference: 2-Intervenor-46 (d) and (e)**

Question(s):

Please provide a full response to 2-Intervenor-46 (d) and (e). It is not clear if all projects of over $2 million have undergone a NWS assessment. Also, the table requested in (e) remains pending.

**Response:**

In response to 2-Intervenor-46 d), BHI considered the applicability of NWS for all material projects (over $2 million) which were the system expansions for the MTSAs and the Dundas St. road widening project. For all these projects an initial assessment was made to determine the feasibility of NWS and it was determined to be a non-viable option in all cases. As such a full NWS assessment was not carried out beyond the initial assessment.

In response to 2-Intervenor-46 e) please see Table 1 below for each project over $2 million.

**Table 1**

| Project | NWSs Considered | Initial Assessment | Viable Option | Third-Party Consultation |
|---|---|---|---|---|
| Dundas St. Road widening | DER / CDM | Mandatory requirement under the PSWHA (Public Service Works on Highways Act). Relocation of existing infrastructure, so DER/CDM are not viable alternatives. | No | None |
| MTSA – Aldershot GO | DER / CDM | Forecasted demand is significant requiring consistent, scalable capacity for new customers, where DERs/CDM would not be practical solutions due to the limitation in supporting new base load (unlike peak demand) and/or requiring complex modifications to the existing network. Need for extending physical infrastructure to serve new customers makes NWs non-viable. | No | None |
| MTSA – Burlington GO | DER / CDM | Forecasted demand is significant requiring consistent, scalable capacity for new customers, where DERs/CDM would not be practical solutions due to the limitation in supporting new base load (unlike peak demand) and/or requiring complex modifications to the existing network. Need for extending physical infrastructure to serve new customers makes NWs non-viable. | No | None |
| MTSA – Appleby GO | DER / CDM | Forecasted demand is significant requiring consistent, scalable capacity for new customers, where DERs/CDM would not be practical solutions due to the limitation in supporting new base load (unlike peak demand) and/or requiring complex modifications to the existing network. Need for extending physical infrastructure to serve new customers makes NWs non-viable. | No | None |

**<u>ED-CQ-8</u>**

**Reference: 8-Intervenor-137**

Question(s):

Page 7 of exhibit 8 indicates that BHI proposes to set the fixed monthly charge for GS>50 kW at the OEB ceiling for 2026. Please estimate the OEB ceiling for each subsequent year in the rate term on a best efforts basis or confirm that it will remain unchanged. Please comment on whether the fixed monthly charge for GS>50 kW is likely to increase over the board ceiling due to inflation during the rate term. This question related to 8-Intervenor-137.

**Response:**

BHI does not have sufficient information in 2027 to 2030 to forecast the OEB ceiling beyond the test year on a cost of service basis as it only has load forecast, cost allocation and revenue requirement information on a 2026 Test Year basis.

During the IRM term, BHI will inflate its revenues at OEB inflation (less its stretch factor). If BHI applies that same OEB inflation rate to the costs that underly the Customer Unit Cost per month - Minimum System with PLCC Adjustment calculation, the OEB ceiling is expected to increase at the same rate as BHI's rates. As such, the inflated fixed monthly charge for GS>50 kW will remain at the inflated OEB ceiling on an annual basis from 2027-2030 (based on OEB inflationary increases only – BHI will not be conducting a cost allocation study with actual costs and load during the IRM term).

**ED-CQ-9**

**Reference: 8-Intervenor-139**

Question(s):

Exhibit 8-Intervenor-139 indicates that BHI charges a $500 application fee for microgeneration connections. Please explain how BHI arrived at that amount, with fully detailed calculations and assumptions. Please explain how BHI is allowed to levy this charge when it is not a specific service charge approved by the OEB.

**Response:**

BHI charges a $500 connection deposit for preparing an offer to connect a microgeneration facility in accordance with Section 5.3.7 of the OEB's Distributed Energy Resources Connections Procedures[1].

[1] Distributed Energy Resources Connections Procedures, Version 2.0, January 27, 2025, p13

**ED-CQ-10**

**Reference: 8-Intervenor-139**

Question(s):

Exhibit 8-Intervenor-139 indicates that BHI charges $1,500 in commissioning on average for microgeneration connections. This is unusual for micro connections. Please explain why BHI charges for commissioning for micro connections and what work the charge typically covers.

**Response:**

BHI clarifies that it only applies commissioning charges to microgeneration connections when the application includes battery storage installation and load displacement. This charge typically covers verification of the nameplate data provided by the Customer on the original application and approved Offer to Connect, equipment labeling, locating of the utility disconnect, anti-islanding testing, reverse power flow testing and any other required testing prior to connecting the DER to BHI's system.

BHI does not apply a commissioning fee to solar net metering microgeneration connections where no battery storage is installed, which is more than 90% of these connections.

**ED-CQ-11**

**Reference: 8-Intervenor-139**

Question(s):

Exhibit 8-Intervenor-139 indicates that BHI charges a $5,413 fee for CIAs for small and medium DER connections. Please explain how BHI arrived at that amount, with fully detailed calculations and assumptions. Please explain how BHI is allowed to levy these charges when they are not a specific service charge approved by the OEB.

**Response:**

BHI engages an Engineering Consulting firm in order to prepare the required Connection Impact Assessment for DERs greater than 10kW as it does not have the internal capacity to prepare these within prescribed timelines. The CIA Cost is a “pass through” charge from BHI’s consultant and reflects market rates for this type of service. BHI provides a breakdown of these costs in Table 1 below.

**Table 1**

| Description | Cost |
|---|---|
| Data Collection and Preliminary Engineering | $2,150.00 |
| Detailed Engineering, Report Finalization, Project Management and Approvals | $3,263.00 |
| Total CIA cost | $5,413.00 |

BHI applies variable connection charges in accordance with Section 3.1.6 of the DSC.

**ED-CQ-12**

**Reference: 8-Intervenor-139**

Question(s):

Exhibit 8-Intervenor-139 indicates that BHI charges a $5,413 fee for CIAs for small and medium DER connections. Most utilities charge considerably less for CIAs for small DER connections. Please justify BHI not doing so. Please justify BHI not have a simplified CIA fee category pursuant to recent amendments to the DSC and DERCP.

**Response:**

BHI engages an Engineering Consulting firm in order to prepare the required Connection Impact Assessment for DERs greater than 10kW as it does not have the internal capacity to prepare these within prescribed timelines. The CIA Cost is a “pass through” charge from BHI’s consultant and reflects market rates for this type of service..

The Connection Impact Assessment calculation and power flow analysis requires the same amount of work, regardless of the size of the DER, which is why BHI charges the same amount for small and medium DER connections.

BHI must comply with Hydro One requirements for the connection of all DERs greater than 10kW and provide an annual report of all connected DERs greater than 10kW with the short circuit contribution per connection, as per signed Threshold Agreements between Hydro One and BHI

BHI is in the process of finalizing a Simplified CIA Fee Category as described in the DERCP Version 2.

**ED-CQ-13**

**Reference: 8-Intervenor-139**

Question(s):

Please indicate how much BHI has collected over the current and previous rate terms in micro generation connection fees and CIA fees for small generation CIAs. Please provide a breakdown by type.

**Response:**

BHI provides the amounts collected over the current rate term in micro generation connection fees and CIA fees for small generation CIAs in Tables 1 and 2 below.

**Table 1: Connection Fees for Small DERs (>10kW and <=500kW)**

| Year | # of Connected Small DERs | Total Connection Fee + CIA |
|---|---|---|
| 2020 | 0 | $0 |
| 2021 | 1 | $40,000 |
| 2022 | 2 | $62,000 |
| 2023 | 0 | $0 |
| 2024 | 2 | $53,500 |
| 2025 YTD | 4 | $21,652 |

**Table 2: Connection Fees for Micro DERs (<10kW)**

| Year | # of Connected Micro DERs | Total Connection Fee + Application Fee |
|---|---|---|
| 2020 | 4 | $2,741 |
| 2021 | 6 | $4,111 |
| 2022 | 22 | $15,074 |
| 2023 | 28 | $21,679 |
| 2024 | 34 | $30,844 |
| 2025 YTD | 8 | $8,454 |

BHI is unable to provide the amounts collected in the previous (2014-20) rate term under the timelines for responding to clarification questions as this data is not readily available.

**ED-CQ-14**

**Reference: 8-Intervenor-139**

Question(s):

Exhibit 8-Intervenor-139 indicates that BHI's Scada threshold was 10 kW in 2021. What is it now and why did it change?

**Response:**

BHI current Scada threshold is for DERs greater than 250kW. It was changed mainly to reduce the overall connection cost to customers for applications less than 250kW.

**<u>ED-CQ-15</u>**

**Reference: 8-Intervenor-142**

Question(s):

Exhibit 8-Intervenor-142 seems to indicate that BHI assesses losses in transformer and conductor purchases by including loss-related specifications that must be met, but does not calculate an all-in lifetime cost of each alternative (e.g. different sized conductors, different transformer brands) in a way that includes the forecast cost of losses arising from each alternative. Please confirm whether we are interpreting this response correctly. If not, please provide clarification, addressing both conductors and transformers. If all in cost are accounted for, please provide an actual example of the relevant paperwork for a conductor and a transformer.

**Response:**

BHI confirms it does not calculate an all-in lifetime cost of each alternative in a way that includes the forecast cost of losses arising from each alternative.

**ED-CQ-16**

**Reference: 8-Intervenor-140 (e)**

Question(s):

Please respond to 8-Intervenor-140 (e). If necessary, please provide a rough estimate of future costs over the rate term based on historical figures, along with underlying calculations.

**Response:**

BHI does not forecast losses (kWh), losses at peak (kW), or cost of losses to customers, but provides estimates on a best-efforts basis as CQ_Attachment_ED-16.

**ED-CQ-17**

**Reference: 8-Intervenor-140**

Question(s):

Exhibit 8-Intervenor-140 describes a number of additional steps that BHI will be taking with respect to losses. Please provide a table listing those, including a column indicating when the step in question will be commenced and completed.

**Response:**

BHI's ability to implement loss reduction measures over the 2026-2030 period is dependent on the additional staffing and OM&A funding proposed in its Application[1], including the Supervisor - System Planning and Grid Modernization. Additionally, investments in SCADA/ADMS and smart field devices (intelligent switches) are critical for implementation of system loss mitigation and grid modernization strategy. BHI's Application contemplates the following timing with respect to additional steps to address losses:

| Loss mitigation measures | Timing |
|---|---|
| Phase load balancing | On-going, demand driven (2026 and onwards) |
| Feeder reconfiguration | Based on system performance, quarterly or as needed (2026 and onwards) |
| Voltage conversion | Annually, as part of system renewal, where applicable (2026 and onwards) |
| System Optimization | Subject to implementation of ADMS / SCADA and integrated smart field devices (anticipated 2028 and onwards) |

BHI will incorporate loss reduction measures as part of broader system improvement plans that consider asset condition, load, feeder congestion, and other operational priorities, the timing of which ultimately drives the additional steps BHI takes with respect to losses.

The Supervisor, System Planning and Grid Modernization will oversee the performance of regular power system analyses on vulnerable feeders, including system loss estimation using CYME software to support the above measures. Aligning the system loss reduction goals with

[1] EB-2025-0051, 8-Intervenor-142 a)

BHI's grid modernization objectives is critical to transition from legacy systems to advanced technologies like ADMS and SCADA, which enable real-time visibility, fault location analytics and predictive outage restoration. The Supervisor, System Planning and Grid Modernization will be directly responsible for evaluating emerging technologies and their impact on system performance/losses and executing the planned implementation. The ensuing capabilities would directly support loss mitigation by:

- Identifying grid weaknesses and optimizing dispatch decisions
- Improving outage resolution through automated fault detection and isolation
- Enhancing data quality for system planning and reliability performance tracking

**ED-CQ-18**

**Reference: 8-Intervenor-144**

Question(s):

Please provide a response to 8-Intervenor-144. It will be very difficult to settle loss-related issues without that response.

**Response:**

Please see below for CIMA+ comments on what it would propose including in a further study during the next rate period to build on the learnings from its June 21, 2023 report, address any potential missing data or other gaps, and explore additional means to cost-effectively reduce distribution losses.

1) Update/validate CYME with latest SCADA/AMI (peak and typical), then screen specific feeders and rank by peak line-loss > 4%, and phase imbalance > 10% to produce a prioritized shortlist.

2) Evaluate feeders with >10% current imbalance for potential targeted load balancing, with emphasis on cost-effective cases.

3) Conduct additional feeder reconfiguration scenarios where the 2023 study showed potential. Run switching/supply-point transfer options with protection/voltage/loading checks and quantify loss reduction and operational impacts.

**SC-CCC-1**

**2-Intervenor-20 and 2-Staff-28 (c)**

a) Please provide a detailed description, and the underlying calculations, for Table 1 to 2-Staff-28(c).

b) To the extent that the response to part (a) does not explain the following, please provide responses to the below questions.

i. Please provide the 2021 average rate base for each of the CIS and GIS assets separately.

ii. Please confirm that the 2021 average rate base (part (i)) was funded in 2021 rates based on a 20% deprecation rate.

iii. Please provide the 2021 depreciation expense ($) reflected in revenue requirement related to the 2021 average rate base for the CIS and GIS assets/

iv. Please provide the 2021 depreciation expense ($) that would have been reflected in revenue requirement in the scenario that the CIS and GIS assets had been applied the correct 10% depreciation rate instead.

v. Please confirm that between 2022-2025 these CIS and GIS assets have been depreciated at a rate of 10% (instead of the 20% reflected in rates).

vi. Please provide the remaining 2026 net CIS and GIS asset values related to the CIS and GIS assets that were funded in 2021 rates.

**Response:**

a) Please refer to BHI's response to Staff-100 a) and b).

b)

**i.** BHI provides the 2021 average rate base for each of the CIS and GIS assets separately of $2,055,288 and $707,030 respectively in Table 1 below.

**Table 1 – Based on 2021 Cost of Service**

| Description | 2021 Opening Net Fixed Assets | 2021 Gross Assets | 2021 Accumulated Deprn | Closing Net Fixed Assets | 2021 Rate Base | 2021 Depreciation Expense at 5 years (20%) | 2021 Depreciation Expense at 10 years (10%) |
|---|---|---|---|---|---|---|---|
| **Calculation** | a | b | c | d=b-c | e=(a+d)/2 | f | g |
| ***Reference*** | *n/a* | *n/a* | *n/a* | *n/a* | *SC-CCC-1 b) i)* | *SC-CCC-1 b) iii)* | *SC-CCC-1 b) iv)* |
| CIS | $2,177,602 | $2,685,428 | $752,454 | $1,932,974 | $2,055,288 | $510,499 | $255,249 |
| GIS | $759,971 | $914,413 | $260,324 | $654,089 | $707,030 | $175,883 | $87,941 |
| **Total** | **$2,937,573** | **$3,599,841** | **$1,012,778** | **$2,587,063** | **$2,762,318** | **$686,382** | **$343,190** |

ii. BHI confirms that the 2021 average rate base (part (i)) was funded in 2021 rates based on a 20% deprecation rate.

iii. Please refer to Table 1 above (2021 depreciation expense reflected in revenue requirement was $686,382).

iv. Please refer to Table 1 above (2021 depreciation expense reflected in revenue requirement would have been $343,190 had the correct 10% depreciation rate been applied).

v. BHI confirms that between 2022-2025 these CIS and GIS assets have been depreciated at a rate of 10% (instead of the 20% reflected in rates).

vi. The remaining 2026 net CIS and GIS asset values related to the CIS and GIS assets that were funded in 2021 rates (2021 opening and 2021 additions only) are $810,743 and $273,229 respectively based on 2021 Cost of Service asset values.

**SC-CCC-2**

**2-Intervenor-50(n) and Exhibit 2, DSP, p. 117**

a) For the 2021-2025 period, please provide the planned budget associated with underground cable replacement and the actual costs associated with this activity.

b) Please explain how this statement: "higher "per unit" costs on underground cable replacements due to installation of new cable in conduits (existing cable was directly buried) to bring the installation up to current standards and make future repairs more cost effective" explains the cost variance experienced with respect to this program. As part of the response, please confirm that the planned budget was based on installing new cable in conduits.

**Response:**

a) BHI provides the planned budget associated with underground cable replacement and the actual costs for the period 2021-2025 in Table 1 below.

**Table 1**

| Underground Cable Replacement | Budget | Actual |
|---|---|---|
| 2021 | $400,000 | $815,152 |
| 2022 | $500,000 | $999,997 |
| 2023 | $500,000 | $1,974,672 |
| 2024 | $500,000 | $1,281,919 |
| 2025 | $500,000 | $793,667 |

b) BHI confirms the planned budget was based on installing new cable in either existing conduits or new conduits. The budget assumed a portion of the cable being replaced would be directly buried and a portion would already be in conduit. A higher than expected proportion of the cable replaced in 2023 and 2024 was directly buried, which resulted in the increased unit cost as BHI was required to install conduit in addition to replacing the cable for these assets. This contributed to the overall cost variance for this program.

**SC-CCC-3**

**2-Intervenor-57(a)**

a) Please explain the need to both replace and reverify, what appears to be, the same meters in given year (i.e., in each year BHI is both replacing and reverifying the same number of smart meters).

**Response:**

a) There is not a need to both replace and reverify the same meters in a given year. BHI included the meters to be replaced in the reverification row in error in Table 1 in 2-Intervenor-57a). BHI provides an update to Table 1 in 2-Intervenor-57a) below to show the number of meters it is intending to reverify vs. replace.

**Table 1**

| | 2021 | 2022 | 2023 | 2024 Actual | 2025 BridgeYear | 2026 Test Year | 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|---|---|---|---|---|---|---|
| Smart Meter Replacement/Reverification | $0 | $226,356 | $402,556 | $406,000 | $277,442 | $2,600,245 | $2,547,332 | $2,597,833 | $774,996 | $747,701 |
| Smart Meter Replacement ($) | N/A | N/A | N/A | N/A | N/A | $2,600,245 | $2,547,332 | $2,597,833 | $774,996 | $747,701 |
| Smart Meter Replacement (Units) | N/A | N/A | N/A | N/A | N/A | 13,668 | 13,668 | 13,668 | 2,233 | 1,655 |
| Smart Meter Replacement ($/Unit) | N/A | N/A | N/A | N/A | N/A | $190 | $186 | $190 | $347 | $452 |
| Smart Meter Reverification ($) | $0 | $226,356 | $402,556 | $406,000 | $277,442 | $0 | $0 | $0 | $0 | $0 |
| Smart Meter Reverification (Units) | 0 | 2,450 | 6,710 | 7,656 | 4,738 | 0 | 0 | 0 | 0 | 0 |
| Smart Meter Reverification ($/Units) | N/A | $92 | $60 | $53 | $59 | N/A | N/A | N/A | N/A | N/A |

**<u>SC-CCC-4</u>**

**2-Intervenor-59(a)**

a) To the extent that they are available, please provide the detailed economic evaluations for each of the three MTSA projects.

**Response:**

a) BHI provides the detailed economic evaluation for the MTSA projects as CQ_Attachment_SC-CCC-4.

**<u>SC-CCC-5</u>**

**4-Intervenor-93(c)**

a) Please explain why bad debt expense is forecast in both the Accounting program ($50k) and the Customer Service program ($150k).

**Response:**

a) Bad debt expense in the Accounting program relates to Miscellaneous Accounts Receivable (e.g. capital contributions, pole attachment revenue, isolations, accidents) and bad debt expense in the Customer Service program relates to A/R associated with customers' electricity and water bills.

**SC-CCC-6**

**2-Intervenor-71**

a) Please explain why BHI would not make an insurance claim related to emergency repairs resulting from storm damage.

**Response:**

a) BHI's insurance policy only covers property damage within 1000 ft of any of its premises (head office and substations), and therefore it is unable to make an insurance claim related to emergency repairs for distribution assets outside of this area. This restriction/exclusion is standard across the industry.

**SC-CCC-7**

**2-Staff-23(d) and (g)**

a) Please advise whether the unit numbers in Row 3 align with the unit designation set out in Table 2. For example, Unit T35 (Table 2) is the same truck as #35 with a score of 30 in 2-Staff-23(d).

**Response:**

a) BHI confirms the unit numbers in Row 3 of IR_Attachment_2-Staff-23d_BHI_07242025 align with the unit designation set out in Table 2 of BHI's response to 2-Staff-23 g).

**SC-CCC-8**

**Updated IRR – Appendix 2-JC and 4-Intervenor-93(c)**

a) Please explain the difference between the 2025 values provided in Updated IRR Appendix 2-JC and the 2025 values provided in 4-Intervenor-93(c).

b) Please confirm that the correct sub-programs within the Stations Program are shown below.

| Description | |
|---|---|
| Salaries and Benefits | |
| Materials - Station Mtce/Ops | |
| Building Operations and Maintenance | |
| Insurance | |
| Telephone/Utilities | |
| Leases/Rent | |
| Oil Tests | |
| Software Maintenance | |
| Station Mtce/Ops - All Other | |
| Total | |

**Response:**

a) BHI provides the difference between the 2025 values provided in Updated IRR Appendix 2-JC and the 2025 values provided in 4-Intervenor-93(c) in Table 1 below.

BHI's response to 4-Intervenor-93 (c) represents its latest forecast of 2025 OM&A results based on known and/or material changes. It includes adjustments to Salaries and Benefits, the effect of which BHI did not have time to flow through and verify all of the OEB Appendices in the time allotted to respond to interrogatories (e.g. Appendix 2-D). In addition, it includes two costs associated with a cyber breach and legal work, which are one-time costs not expected to recur in 2026. Therefore these three amounts were excluded from the Updated IRR Appendix 2-JC.

**Table 1**

| Description | 2025 Bridge Year | Comments |
|---|---|---|
| **Total OM&A - 2-JC - As Filed - Apr 16/2025** | **$26,759,971** | |
| Locates | $45,196 | Cost increase persists into 2026 |
| OEB Costs | $13,745 | Cost increase persists into 2026 |
| **Total OM&A - 2-JC - IRRs - Jul 24/2025** | **$26,818,912** | |
| Salaries and Benefits | -$34,874 | 2025 impact - will not persist into 2026 |
| Cyber Breach Costs | $113,076 | 2025 impact - will not persist into 2026 |
| Legal Costs | $50,000 | 2025 impact - will not persist into 2026 |
| **Total OM&A - 4-Intervenor-93c)** | **$26,947,114** | |

b) BHI confirms that the correct sub-programs within the Stations Program are shown in Table 2 below.

**Table 2**

| Description |
|---|
| Salaries and Benefits |
| Materials - Station Mtce/Ops |
| Building Operations and Maintenance |
| Insurance |
| Telephone/Utilities |
| Leases/Rent |
| Oil Tests |
| Software Maintenance |
| Station Mtce/Ops - All Other |
| **Total** |

**SC-CCC-9**

**4-Intervenor-121(b)**

a) Please further discuss BESI's use of the head office building (e.g., how many staff work out of that location, does BESI require storage space, etc.).

**Response:**

a) Both of BESI's staff members — the General Manager and the Executive Assistant — work out of the head office building. They each have dedicated office space.

While most of their records are stored electronically, some hard copy documents are kept on office shelves. BESI also temporarily stores its EV charging stations in the building's storage area until they are installed at their intended locations.

The staff rarely use the office meeting rooms, as they primarily hold meetings via Microsoft Teams and offsite. They use the building's parking facilities for their personal vehicles.

**SEC-CQ-1**

**Reference: [IRR Attachment_OEB_ACM_ICM_Model_BHI_07242025]**

Question(s):

Please complete tab 10 of the ACM Model.

**Response:**

BHI provides the updated ACM model with the completed Tab 10 as Attachment_OEB_ACM_ICM_Model_BHI_08112025.

**SEC-CQ-2**

**Reference: [IRR Attachment_OEB_ACM_ICM_Model_BHI_07242025]**

Question(s):

Please provide estimated 2027 bill impacts, by rate class, for the proposed ACM.

**Response:**

BHI provides the estimated 2027 monthly bill impacts, by rate class, for the proposed ACM project in Table 1 below. The bill impacts are based on the rate riders calculated in Tab “11. Rate Rider Calc.” of the updated ACM model filed in response to SEC-CQ-1.

**Table 1**

| Rate Class | Unit | # Units | ACM bill impact excluding HST |
|---|---|---|---|
| RESIDENTIAL | kWh | 750 | $0.03 |
| GENERAL SERVICE LESS THAN 50 kW | kWh | 1,500 | $0.02 |
| GENERAL SERVICE 50 TO 4,999 kW | kW | 200 | $0.72 |
| STREET LIGHTING | kW | 0.22 | $0.00 |
| UNMETERED SCATTERED LOAD | kWh | 2,000 | $0.01 |

**<u>SEC-CQ-3</u>**

**Reference: 2-Intervenor-13 (d)**

Question(s):

a) Please confirm that the calculated Revenue Requirement does not include the increased depreciation expense (line n).

b) Should SEC understand the response to be that in 2026 BHI received $1,139,889 less in capital contributions as a result of the referenced amendments to the DSC?

c) Is there any impact related to the application of the amendments in 2025 that impact the 2026 revenue requirements? If so, please provide details including the impact on the 2026 revenue requirement.

**Response:**

a) The calculated revenue requirement excluded the increased depreciation expense (line n) in error. BHI provides the corrected estimate of the revenue requirement impact in 2026 resulting from the changes to connection and revenue horizon rules in Table 1 below.

**Table 1**

| Description | Capital Structure | Calculation | % Rate (as Filed) | Calculation |
|---|---|---|---|---|
| Deemed STD | 4.0% | a | 3.91% | e |
| Deemed LTD | 56.0% | b | 4.36% | f |
| Deemed Debt | 60.0% | c = a+b | 4.33% | g = (a*e/c)+(b*f/c) |
| Deemed Equity | 40.0% | d | 9.00% | h |
| PILS | | | 26.50% | i |

| Description | $ | Calculation |
|---|---|---|
| **Fixed Assets Opening Balance 2026** | **$0** | j |
| **Capital Expenditures** | **$1,130,889** | k |
| Work-in-Progress (example) | 0 | l |
| **In-Service Additions** | **$1,130,889** | m = k +l |
| Straight Line Depreciation at 2.5% at 1/2 year | (14,136) | n = .025*m/2 |
| **Fixed Assets Closing Balance 2026** | **$1,116,753** | o = m+n |
| **Average Fixed Assets** | **$558,376** | p = (j+o)/2 |
| **Rate Base** | **$558,376** | q = p |
| Deemed Interest | $14,520 | r = q*c*g |
| Deemed Equity | $20,102 | s = q*d*h |
| PILS | $7,247 | t = y |
| **Revenue Requirement** | **$56,005** | **u = r+s+t-n** |

| Description | $ | Calculation |
|---|---|---|
| Deemed Equity | $20,102 | v = s |
| Tax Rate | 26.50% | w = i |
| PILS before Gross Up | $5,327 | x = v*w |
| **Gross Up PILS** | **$7,247** | y = x/(1-w) |

b) Yes, BHI expects to receive $1,130,889 less in 2026 capital contributions as a result of the referenced amendments to the DSC.

c) No, there are no impacts related to the application of the amendments in the 2025 Bridge Year that impact the 2026 Test Year revenue requirements.

**SEC-CQ-4**

**Reference: 2-Intervenor-52**

Question(s):

In EB-2024-0010, the OEB made certain reductions to the requested ICM amounts for the Dundas St. Road Widening project. Please explain how the OEB's findings have been incorporated into the amounts BHI is seeking to add to rate base for the project.

**Response:**

In accordance with the OEB's Decision and Order[1], BHI reduced its requested ICM funding (which was capped at the Maximum Eligible Incremental Capital amount) for the purposes of its 2025 ICM rate rider as shown in Table 1 below.

**Table 1**

| Description | 2025 |
|---|---|
| Capital Forecast | $16,891,993 |
| Less: Materiality Threshold | $11,771,200 |
| **Maximum Eligible Incremental Capital** | **$ 5,120,792** |
| Replacing Assets in Poor Condition | $ (197,757) |
| Higher Unit Costs vs. Waterdown Rd Project | $ (160,692) |
| **Approved ICM Funding per Decision and Order** | **$ 4,762,343** |

BHI did not make the reductions identified in Table 1 to the amounts it is seeking to add to rate base for this project.

[1] EB-2024-0010, Decision and Order, December 17, 2024

## SEC-CQ-5

**Reference: 5-Staff-70**

Question(s):

Please provide the source and copy of the referenced debt rate quote.

**Response:**

The debt rate quote was from TD Bank and is provided In Table 1 below. The quote of 4.60% is a fixed rate for 10 years and based on a 10 year amortization.

**Table 1**

| As of July 8, 2025 | Interest Rate Type | Rate Term | | | | | | Drawdown Terms/ Drawdown Availability |
|---|---|---|---|---|---|---|---|---|
| | | 1 yr. | 2 yr. | 3 yr. | 5 yr. | 7 yr. | 10 yr. | |
| Capex Term Loan $15,000,000 CAD | Fixed Rate (% p.a.) based on 10 yr. amortization | 3.90 | 3.90 | 4.10 | 4.30 | 4.50 | 4.60 | Facility is subject to a maximum of 3 draws and $10,000,000 per annum. |
| | Variable (via CORRA*) | CORRA + 1.40% spread | | | | | | The minimum amount of a drawdown by way of Term CORRA Loan and Daily Compounded CORRA Loan is CAD$1,000,000. BHI shall advise the Bank of the requested contract maturity date or interest period for Term CORRA Loans and for Daily Compounded CORRA Loans under a committed facility. BHI shall provide the Bank with three (3) Business Days' notice of a requested Term CORRA Loan and Daily Compounded CORRA Loan. |

**VECC-CQ-1**

**Reference:**

**1-Staff-1, Attachment_Load_Forecast_Model_BHI_07242025**

Question(s):

a) With respect to the Customer Count Tab, please explain the basis for the January 2026 forecast customer count for each rate class.

**Response:**

a) The 2026 customer count forecast for each class is calculated as the geometric mean growth rate from 2015 to 2024 (2017 to 2024 for the Street Lighting and USL rate classes) applied to the forecast 2025 customer count of each class. The 2025 customer count forecast is an average of 2025 monthly customer counts, which includes actual January to May 2025 customer counts and forecast June to December customer counts. June 2025 customer counts are forecast based on the monthly average geometric growth rate applied to actual May 2025 customer counts and the remaining customer counts are forecast based on the monthly average geometric growth rate applied to the forecast count from the preceding month.

**VECC-CQ-2**

**Reference:**

**1-Staff-1, Attachment_Load_Forecast_Model_BHI_07242025**

Question(s):

a) With respect to the actual 2024 monthly usage reported in the Monthly Data Tab for all classes except Street Lighting, please explain why the values in the updated Load Forecast differ from those reported in the Load Forecast Model filed with the Application.

**Response:**

a) Actual 2024 monthly volumes were corrected in the updated Load Forecast and now align with the RRRs and the RTSR model.

**VECC-CQ-3**

**Reference:**

**1-Staff-1, Attachment_Load_Forecast_Model_BHI_07242025**

Question(s):

a) With respect to the Res Predicted Monthly Tab, the values for OEA_GDP are sourced from the Monthly Data Tab which, in turn, sources the values from the Economic Tab. However, it appears that in sourcing the OEA_GDP values from the Economic Tab the formulae used in the Monthly Data Tab reference the wrong year (e.g., values for 2023 in the Economic Tab are used as values for 2024 in the Monthly Data Tab). Please confirm whether this is the case.

b) If confirmed, does the fact that the Monthly Data Tab and the Res Predicted Monthly Tab use the incorrect historic OEA_GDP values for January 2015-May 2025 mean that the Residential regression model was estimated using incorrect data?
   i. If not, why not?
   ii. If yes, please provide an updated Load Forecast using the correct data to estimate the Residential model.

c) Please review the data used in the estimation of the regression models for the other classes and confirm that, in each case, the correct data values were used.

**Response:**

a) BHI confirms the formulae used in the Monthly Data Tab referenced the wrong year in sourcing the OEA_GDP values from the Economic Tab.

b) Yes, the residential regression model was estimated using incorrect data, specifically that the Monthly Data Tab and the Res Predicted Monthly Tab use the incorrect historic OEA_GDP values for January 2015-May 2025.

   i. See above response.

   ii. An updated load forecast is provided as Attachment_Load_Forecast_Model_BHI_08112025. The 2026 Residential kWh forecast in this model is 527,179,883 kWh. The OEA GDP variable is not statistically significant with this correction so it has been removed. For reference, the model with the corrected figures that maintains the OEA GDP variable is 536,921,797 kWh.

c) BHI reviewed the data used for the regressions and predicted volumes for the General Service < 50 kW and General Service > 50 kW classes and the correct data values were used.

**VECC-CQ-4**

**Reference:**

**3-Intervenor-84 a) and c)**

Question(s):

a) Do the 2026 forecast of 578,681,571 kWh (per 84 a)) and the 2026 forecast of 543,620,703 kWh (per 84 c)) both represent a No-CDM forecast similar to the 583,399,477 kWh value from the initial Application and, if not, what do they represent?

**Response:**

a) No, the 578,681,571 and 543,620,703 kWh figures are the final forecast volumes after persisting CDM is removed, additional loads are added, and the forecast CDM adjustment is applied. The No-CDM forecast figure corresponding to part a) is 607,632,355 kWh and the No-CDM forecast figure corresponding to part c) is 572,571,487.

**VECC-CQ-5**

**Reference:**

**3-Intervenor 85 b) and 86 b)**

Question(s):

a) The GS>50 2026 forecast reported in 86 b) for the model with a COVID variable (177,886,088 kWh) is the same as that reported in 85 b) for the GS<50 class. Please review and correct the forecast values as required.

**Response:**

a) BHI's response to 3-Intervenor 86 b) was incorrect and referenced the GS<50kW values in error. It should have stated "The statistical results for the three scenarios are provided below. The forecast for the scenario with the highest COVID variable statistical significance is scenario 3, which produces a forecast of 768,252,481 kWh in 2025 and 749,173,002 kWh in 2026".

**VECC-CQ-6**

**Reference:**

**3-Intervenor 86 c), 1-Staff-1,Attachment_Load_Forecast_Model_BHI_07242025, Total Additional-Lost Loads Tab**

Question(s):

a) Please explain why the adjustment to the GS>50 2026 load forecast for the "lost customer" uses 2023 usage as the base when the updated load forecast uses actual data up to May 2025, which includes months where the customer was reclassified to the GS<50 class and includes a month after the closure date for the customer.

**Response:**

a) The comment on reclassification to the GS<50 kW class in 3-Intervenor-86c) was a general comment on customers that are reclassified from GS>50 kW to GS<50 kW, and not necessarily ceasing operations. The "lost customer" was not reclassified to the GS<50 kW class.

When BHI updated its load forecast for actuals up to 2025 May YTD it inadvertently did not update the calculations for the "Lost Customer" to incorporate actual data up to May 2025 instead of 2023 usage. 2024 and 2025 actual demand was 13,081 kW as compared to in the "Total Additional-Lost Loads" tab of 17,900 kW in the Load Forecast model. The customer's demands in 2023 remain a better reflection of the billed loads that are lost when the customer ceased operations.

The adjustment for lost load was made to the GS>50 kW forecast that uses 125 months of data. The "Lost Customer" load was not included in only one of these months (May 2025) and as such the absence of this load in May 2025 does not materially impact the Test Year forecast.

**VECC-CQ-7**

**Reference:**

**7-Intervenor-132, Attachment 11_Load_Profile_Derivation_BHI_04162025**

Question(s):

a) With respect to New York utilities' TOU rates, what hours of the weekday are considered to be on-peak?

**Response:**

a) Peak hours differ by utility. Con Edison's on-peak hours are from 8:00am to midnight and super-peak hours are 2:00pm to 6:00pm. Central Hudson's on-peak hours are from 2:00pm to 7:00pm. National Grid's on-peak hours are 5:00pm to 8:00pm in the winter months and 11:00am to 5:00pm in the summer months.

**VECC-CQ-8**

**Reference:**

**7-Intervenor-133**

Question(s):

a) Please explain the basis on which each of the four accounts included in the derivation of the Billing and Collecting weighting factors is allocated to the customer classes.

**Response:**

a) The four accounts included in the derivation of the Billing and Collecting weighting factors are allocated to the customer classes as follows:

- Customer Billing (5315) – based on direct actual billing costs by rate class and indirect allocated costs (e.g. testing CIS changes required as a result of changes in regulations)
- Collecting (5320) – based on each rate class's historical Bad Debt experience
- Collection Charges (5330) – based on each rate class's historical Bad Debt experience
- Misc Customer Accounts Expense (5340) – allocated to each rate class based on their proportionate share of the total costs for USoAs 5315, 5320 and 5330.

**VECC-CQ-9**

**Reference:**

**1-Staff-1, Attachment_RRWF_BHI_07242025**

Question(s):

a) With respect to the Cost Allocation Tab, please explain the material change in the Status Quo Revenue/Cost Ratio for the GS<50 class as between the application (108.48%) and the interrogatory responses (123.79%).

**Response:**

a) The material change in the Status Quo Revenue/Cost Ratio for the GS<50 class from the Application to the interrogatory responses was driven by an error in the Service weighting factors in the application, which were based on gross cost instead of installed cost (paid by BHI). Please refer to 7-Staff-80 for further details.

**VECC-CQ-10**

**Reference: 1-Staff-1, Attachment_Load_Forecast_Model_BHI_07242025, VECC-CQ-1**

Question(s):

With respect to the Customer Count Tab, please explain the basis for the different formula used for the January 2026 forecast customer count for each rate class.

**Response:**

The calculation of annual customer counts in rows 5 to 16 of the Customer Count tab is the basis for the forecast number of customers in 2026. The calculations in rows 24 to 59 provide monthly counts in case monthly forecast counts are required because the customer count variable is used in a class's regression model.

The formula for January 2026 is different in order to impute the correct starting point so the forecast average 2026 monthly customer count equals the 2026 annual customer count. The formula for January 2026 ensures that, for each rate class, the correct starting point is such that the monthly geometric growth rate applied to the January 2026 count, and each subsequent month, results in month customer counts that are, on average for the year, equal to the annual customer count forecast calculated in row 16.

**VECC-CQ-11**

**Reference:**

CQ-Staff-106
2-Intervenor-34

Question(s):

a) What is the relationship between a connection and the addition of a new customer?
b) What is the relationship between a buyback from developers and connections?
c) Provide # of connections in 2022 and 2023.

**Response:**

a) In some cases, one new connection results in the addition of a new customer. However, there can be a new connection without a corresponding increase to the number of customers in the following situations:
   - Houses being torn down and rebuilt where a new meter gets installed;
   - Service upgrades that result in the meter having to be replaced;
   - Net metering installations where the meter has to be replaced.

   Additionally, new customer connections are counted regardless of when they happen in the year, while the customer count is an average (e.g. a new connection at the beginning of July counts as 1 connection and 0.5 of a customer count). This inflates the number of connections compared with the number of new customers.

   Lastly, the customer count includes decreases when customers disconnect.

b) When a developer chooses the alternative bid option in the DSC for subdivision development, and transfers those assets to BHI at the transfer price, BHI refers to this as a buyback[1]. The connections or units within the subdivision translate into a one-to-one addition of new customers in the month of the connection. This does not necessarily translate into one customer for a full year.

c) BHI provides the # of connections in 2022 and 2023 in Table 1 below.

[1] DSC, Section 3.2.18

**Table 1**

| New Connections | # |
|---|---|
| 2022 | 316 |
| 2023 | 288 |
| 2024 | 457 |
| 2025 | 524 |
| 2026 | 612 |
| 2027 | 700 |
| 2028 | 1,253 |
| 2029 | 1,341 |

**VECC-CQ-12**

**Reference: 3-Intervenor-84, 3-Intervenor-85, 3-Intervenor-86**

Question(s):

Please provide the results (i.e., regression equation, regression statistics and 2026 forecast) where the model also includes the following:

i) Residential customer count as an explanatory variable (per BHI's response to 3-Intervenor-84 a);

ii) COVID-related variable as an explanatory variable for the Residential class model (per BHI's response to 3-Intervenor-84 c), Scenario 3);

iii) COVID-related variable as an explanatory variable for the GS<50 class model (per BHI's response to 3-Intervenor-85 b), Scenario 3);

iv) COVID-related variable as an explanatory variable for the GS>50 class model (per BHI's response to 3-Intervenor-86 b), Scenario 3);

**Response:**

BHI provides a load forecast with the above explanatory variables included as Attachment_VECC-CQ-12_Load_Forecast_Model_BHI_08112025. The 2026 forecast kWh volumes for this scenario are provided in Table 1 below.

**Table 1**

| 2026 | kWh |
|---|---|
| Residential | 543,759,271 |
| GS < 50 kW | 171,402,772 |
| GS > 50 kW | 747,394,113 |

The regression equation and statistics are provided in Tables 2, 3 and 4 below. The Residential regression excludes the OEA_GDP variable because that variable is not statistically significant with the customer count and COVID variables.

**Table 2**

| Model 2: Prais-Winsten, using observations 2015:01-2025:05 (T = 125) | | | | |
|---|---|---|---|---|
| Dependent variable: Res_NoCDM | | | | |
| rho = 0.127885 | | | | |
| | coefficient | std. error | t-ratio | p-value |
| const | (77,106,558) | 12,916,821 | (5.97) | 0.0000 |
| HDD14 | 14,902 | 1,500 | 9.93 | 0.0000 |
| CDD14 | 80,873 | 3,309 | 24.44 | 0.0000 |
| Shoulder | (2,711,626) | 407,363 | (6.66) | 0.0000 |
| MonthDays | 1,533,633 | 161,227 | 9.51 | 0.0000 |
| Residential_Customers | 1,121 | 195 | 5.75 | 0.0000 |
| COVID3HDDInt84 | 6,408 | 1,977 | 3.24 | 0.0016 |
| COVID3CDDInt84 | 17,046 | 3,391 | 5.03 | 0.0000 |
| Statistics based on the rho-differenced data | | | | |
| Sum squared resid | 2.72E+14 | S.E. of regression | | 1,523,619 |
| R-squared | 0.9642 | Adjusted R-squared | | 0.9621 |
| F(7, 117) | 387.07 | P-value(F) | | 9.42E-78 |
| rho | -0.0238 | Durbin-Watson | | 1.9209 |
| Statistics based on the original data | | | | |
| Mean dependent var | 46,402,777 | S.D. dependent var | | 7,824,598 |

**Table 3**

| Model 2: Prais-Winsten, using observations 2015:01-2025:05 (T = 125) | | | | |
|---|---|---|---|---|
| Dependent variable: GS_lt_50_NoCDM | | | | |
| rho = 0.389371 | | | | |
| | coefficient | std. error | t-ratio | p-value |
| const | (10,013,973) | 1,855,098 | (5.40) | 0.0000 |
| HDD14 | 5,082 | 330 | 15.40 | 0.0000 |
| CDD14 | 12,142 | 685 | 17.73 | 0.0000 |
| OEA_GDPChange | 4 | 2 | 1.90 | 0.0601 |
| GS_lt_50_Customers | 2,269 | 293 | 7.75 | 0.0000 |
| Shoulder | (156,935) | 84,812 | (1.85) | 0.0668 |
| MonthDays | 350,950 | 30,654 | 11.45 | 0.0000 |
| COVID3Int85_86 | (2,084,853) | 214,022 | (9.74) | 0.0000 |
| Statistics based on the rho-differenced data | | | | |
| Sum squared resid | 1.30E+13 | S.E. of regression | | 333,948 |
| R-squared | 0.9215 | Adjusted R-squared | | 0.9168 |
| F(7, 117) | 182.27 | P-value(F) | | 8.03E-60 |
| rho | -0.0273 | Durbin-Watson | | 1.7898 |
| Statistics based on the original data | | | | |
| Mean dependent var | 14,767,664 | S.D. dependent var | | 1,155,160 |

**Table 4**

| Model 3: Prais-Winsten, using observations 2015:01-2025:05 (T = 125) | | | | |
|---|---|---|---|---|
| Dependent variable: GS_gt_50_NoCDM | | | | |
| rho = 0.482605 | | | | |
| | coefficient | std. error | t-ratio | p-value |
| const | 13,642,994 | 3,513,207 | 3.88 | 0.0002 |
| HDD10 | 17,703 | 1,299 | 13.63 | 0.0000 |
| CDD14 | 46,258 | 1,935 | 23.90 | 0.0000 |
| Trend | (58,060) | 6,514 | (8.91) | 0.0000 |
| Dec | (2,274,410) | 393,826 | (5.78) | 0.0000 |
| MonthDays | 1,886,530 | 114,171 | 16.52 | 0.0000 |
| Tor_FTEAdjChange | 5,396 | 1,743 | 3.10 | 0.0025 |
| COVID3Int85_86 | (5,745,197) | 974,743 | (5.89) | 0.0000 |
| Statistics based on the rho-differenced data | | | | |
| Sum squared resid | 2.11E+14 | S.E. of regression | | 1,341,483 |
| R-squared | 0.9381 | Adjusted R-squared | | 0.9344 |
| F(7, 117) | 243.84 | P-value(F) | | 1.20E-66 |
| rho | -0.0857 | Durbin-Watson | | 2.1632 |
| Statistics based on the original data | | | | |
| Mean dependent var | 72,584,501 | S.D. dependent var | | 5,236,218 |

**SCHEDULE C**

**ACCOUNTING ORDERS**

**BURLINGTON HYDRO INC.**

**EB-2025-0051**

**NOVEMBER 25, 2025**

**Accounting Order #1**
**Burlington Hydro**
**Inc. EB-2025-0051**

**Account 1508 Sub-account – System Access Variance Account - Revenue Requirement Differential Variance Account**

Effective January 1, 2026, BHI shall establish a new variance account: Account 1508 Sub-account – System Access Variance Account - Revenue Requirement Differential Variance Account ("System Access Variance Account" or "SAVA"). The purpose of this sub-account is to record the revenue requirement associated with the difference between actual 2026 System Access capital additions and the forecasted 2026 System Access capital additions in the Application, net of capital contributions, in the 2026 Test Year and the resulting impact during the IRM period. The baseline net capital additions used to determine any variance will be $13,500,384. The account will be asymmetrical, such that (i) the maximum amount of additional 2026 System Access net capital additions used to calculate the revenue requirement recorded in the account will be limited to $2M above the baseline, reflecting BHI's forecast budget in the application, while (ii) the revenue requirement impact of the aggregate amounts of actual 2026 System Access net capital additions that are less than the baseline will be fully recorded in the account.

If the revenue requirement impact is higher than forecast in the 2026 Test Year (i.e., the actual System Access net capital additions in the Test Year exceed forecasted System Access net capital additions up to a maximum of $2M), BHI will make a debit entry in the System Access Variance Account representing a collection from ratepayers. If the revenue requirement impact is lower than forecast in the 2026 Test Year (i.e., the actual System Access net capital additions in the 2026 Test Year are lower than forecasted System Access net capital additions), BHI will make a credit entry in the System Access Variance Account representing a refund to ratepayers. The revenue requirement impact includes depreciation, interest, ROE and PILs. To calculate the PILs expense, the Capital Cost Allowance ("CCA") under the Accelerated Investment Incentive shall be used, which is consistent with the treatment of the CCA on the net capital additions in the 2026 Test Year. All components of cost of capital will use the weighted average cost of capital, as approved in BHI's Cost of Service Application EB-2025-0051.

For each rate year from 2027 until BHI's next rebasing, BHI will make further entries into the account equal to the revenue requirement impact in the 2026 Test Year associated with the difference between actual and budgeted net capital additions in respect of System Access (i.e. the 2026 debit or credit entry described above), escalated annually by the OEB Price Cap IR annual adjustment (Inflation minus X-factor) in effect for that year as well as growth in billing determinants.

The System Access Variance account shall be disposed of on a final basis as part of any Advanced Capital Module (“ACM”) or Incremental Capital Module (“ICM”) application that BHI may file during the IRM period, or at its next rebasing application. This account will accrue carrying charges at OEB-prescribed rates until final disposition.

The following are sample journal entries should actual System Access in-service net capital additions exceed budgeted System Access in-service net capital additions in the 2026 Test Year.

| | Debit | Credit |
|---|---|---|
| DR. Account 1508 - Sub-account SAVA – Depreciation | x,xxx.xx | |
| DR. Account 1508 - Sub-account SAVA – Deemed Interest Expense | x,xxx.xx | |
| DR. Account 1508 - Sub-account SAVA – Return on Equity | x,xxx.xx | |
| DR. Account 1508 - Sub-account SAVA – PILs | x,xxx.xx | |
| CR. Account 4080 - Distribution Services Revenue | | x,xxx.xx |
| | | |
| DR. Account 1508 - Sub-account SAVA – Carrying Charges | x,xxx.xx | |
| CR. Account 6035 - Interest Expense | | x,xxx.xx |

**Accounting Order #2**
**Burlington Hydro**
**Inc. EB-2025-0051**

**Account 1508 – Cloud Computing Implementation Costs - ERP Replacement**

The Parties agree to establish a new deferral account to record cloud computing implementation and ongoing subscription costs in respect of BHI's Enterprise Resource Planning system ("ERP") replacement. Any amounts recorded in the account must be offset by the revenue requirement of the on-premise ERP replacement capital expenditures avoided during the IRM period through the implementation of a cloud-based ERP solution. For clarity, the avoided ERP replacement capital expenditures shall be no greater than $2,143,000, but may be lower if some amounts related to this project are capitalized in accordance with IFRS. The generic Incremental Cloud Computing Implementation Costs Account (Account 1511) will be closed in accordance with the Board's "Cost of Capital and Other Matters" Decision on March 27, 2025[1].

The following are sample journal entries to record cloud computing implementation costs in respect of BHI's ERP replacement:

Dr. 1508 Cloud Computing Implementation Costs – ERP Replacement

Cr. XXXX OM&A Account(s) associated with cloud costs, as applicable

*To record cloud computing ERP implementation costs incurred*

Dr. 4080 Distribution Revenue

Cr. 1508 Cloud Computing Implementation Costs – ERP Replacement, Sub-account Revenue Requirement

*To record the revenue requirement impact of the cloud computing ERP implementation costs which otherwise would have been recorded in capital*

[1] EB-2024-0063, Section 3.8, p103

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Dr. 1508 Cloud Computing Implementation Costs – ERP Replacement, Sub-account Carrying Charges

Cr. 6035 Other Interest Expense

*To record the carrying charges on the net monthly opening balance in Account 1508 - Cloud Computing Implementation Costs – ERP Replacement*

The net monthly opening balance of Account 1508 Cloud Computing Implementation Costs – ERP Replacement shall be used to calculate the carrying charges in this account. The net monthly opening balance shall be calculated as:

1. The cumulative cloud computing ERP implementation costs incurred and recorded in Account 1508 Cloud Computing Implementation Costs – ERP Replacement

   net of

2. The cumulative revenue requirement impact of the cloud computing ERP implementation costs which otherwise would have been recorded in capital and recorded in Account 1508 Cloud Computing Implementation Costs – ERP Replacement, Sub-account Revenue Requirement