ONTARIO ENERGY BOARD

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 EPCOR Electricity Distribution Ontario Inc. for an order approving just and reasonable rates and other charges for electricity distribution beginning October 1, 2023.

EB-2022-0028

EPCOR ELECTRICITY DISTRIBUTION ONTARIO INC.

SETTLEMENT PROPOSAL

December 9, 2022

Appendix A – Updated 2023 Revenue Requirement Work Form
Appendix B – Updated 2023 Bill Impacts
Appendix C – Updated 2023 Proposed Tariff of Rates and Charges
Appendix D – Pre-Settlement Clarification Responses
Appendix E – Updated Low Voltage Rates Calculation
Appendix F – Updated Group 2 DVA Balances for Disposition

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:

EEDO_2023 Chapter 2 Appendices_20221209
EEDO_2023 Revenue Requirement Workform_20221209
EEDO_2023 Cost Allocation Model_20221209
EEDO_2023 Tariff Schedule & Bill Impact Model_20221209
EEDO_2023 DVA_Continuity_Schedule_20221209

A. BACKGROUND

EPCOR Electricity Distribution Ontario Inc. ("EPCOR") filed a Cost of Service application with the Ontario Energy Board ("OEB") on May 27, 2022 under section 78 of the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, (Schedule B) (the "Act"), and is seeking approval for changes to the rates that EPCOR charges for electricity distribution and other charges, to be effective October 1, 2023 (OEB Docket Number EB-2022-0028) (the "Application").

The OEB issued and published a Notice of Hearing dated June 13, 2022, and issued Procedural Order No. 1 on July 15, 2022, the latter of which, among other things, required the parties to the proceeding to develop a proposed issues list and scheduled a Settlement Conference to take place from September 7-8, 2022 and if needed on September 9, 2022.

On June 29, 2022, OEB Staff sent a set of clarification questions (OEB Staff Clarification Questions) to EPCOR and EPCOR responded on July 12, 2022.

On July 27, 2022, pursuant to Procedural Order No. 1, OEB Staff submitted a proposed issues list and on July 28, 2022, the OEB approved the issues list for the purposes of this proceeding (the "Approved Issues List").

EPCOR filed its responses to interrogatories with the OEB on August 25, 2022. As part of its Interrogatory Responses, EPCOR updated certain evidence and several spreadsheet models. EPCOR also included a cover letter with a request to modify the effective date of the Application to comply with the terms of the MAAD Decision and Order (EB-2017-0373/0374) wherein the OEB approved a request to defer the rate rebasing of CollusLDC for five years from the date of closing (October 1, 2018) of the share acquisition transactions. EPCOR also indicated that it would be filing additional evidence supporting this amendment.

As a result, on September 9, 2022 the OEB issued a letter stating that the application was to be placed in abeyance pending the submission of additional evidence regarding the effective date. EPCOR submitted the additional evidence on September 14, 2022.

EPCOR responded to additional interrogatories based on the September 14 evidence on October 11, 2022.

A Settlement Conference was convened from November 7-9, 2022 in accordance with the OEB's *Rules of Practice and Procedure* (the "Rules") and the OEB's *Practice Direction on Settlement Conferences* (the "Practice Direction").

Sarah Daitch of Daitch & Associates acted as facilitator for the Settlement Conference that lasted for three days.

EPCOR and the following intervenors participated in the Settlement Conference:

- School Energy Coalition (SEC);
- Vulnerable Energy Consumers Coalition (VECC); and

- Environmental Defence (ED)

The Small Business Utility Alliance (SBUA) and Environmental Defence (ED), both intervenors in this proceeding, are taking no position on the issues that were settled or partially settled. However, neither SBUA nor ED oppose the position reached by the remaining parties and both will focus their attention on issues still outstanding. EPCOR and the intervenors are collectively referred to as the "Parties".

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

B. SETTLEMENT PROPOSAL PREAMBLE

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

The Parties acknowledge that the Settlement Conference, including any settlement information related thereto, is privileged and confidential in accordance with the Practice Direction. The Parties understand that confidentiality in that context does not have the same meaning as confidentiality in the OEB's *Practice Direction on Confidential Filings* and the rules of that latter document do not apply. Instead, in the Settlement Conference, and in this Settlement Proposal, the Parties have interpreted "confidential" to mean that the documents and other information provided during the course of the Settlement Conference, the discussion of each issue, the offers and counter-offers, and the negotiations leading to the settlement - or not - of each issue during the Settlement Conference and during the preparation of this Settlement Proposal are strictly privileged and without prejudice. None of the foregoing is admissible as evidence in this proceeding, or otherwise, with one exception, the need to resolve a subsequent dispute over the interpretation of any provision of this Settlement Proposal. Further, the Parties shall not disclose those documents or other 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 as the Parties.

This Settlement Proposal is organized in accordance with the Approved Issues List. This Settlement Proposal provides a brief description of each of the settled issues, together with references to the evidence submitted for the record in this proceeding. The Parties agree that references to the "evidence" in this Settlement Proposal shall, unless the context otherwise requires, include, in addition to the Application, the written responses to interrogatories and other components of the record up to and including the date hereof, (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 Responses).

The Parties for each settled issue agree that the evidence in respect of each 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 EPCOR. While the Parties have reviewed the Appendices, the Parties are relying on the accuracy of those Appendices and the underlying evidence in entering into this Settlement Proposal.

"Complete Settlement" means an issue for which complete settlement was reached by all Parties, and if this Settlement Proposal is accepted by the OEB, none of the Parties (including Parties who take no position on that issue) will adduce any evidence or argument during an oral hearing, if applicable, in respect of the specific issue.		# issues settled: **3**
"Partial Settlement" means an issue for which there is partial settlement, as EPCOR and the Intervenors who take any position on the issue were able to agree on some, but not all, aspects of the particular issue. If this Settlement Proposal is accepted by the OEB, the Parties (including Parties who take no position on the Partial Settlement) will only adduce evidence and argument during an oral hearing on the portions of the issue for which no agreement has been reached.		# issues partially settled: **2**
"No Settlement" means an issue for which no settlement was reached. EPCOR and the Intervenors who take a position on the issue will adduce evidence and/or argument at an oral hearing on the issue.		# issues not settled: **7**

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

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

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

Unless otherwise expressly stated in this Settlement Proposal, the settlement of any particular issue in this proceeding and the positions of the Parties in this Settlement Proposal are without prejudice to the rights of the Parties to raise the same issue and/or to take any position thereon in any other proceeding, whether or not EPCOR is a party to such proceeding.

In this Settlement Proposal, where any of the Parties "accept" the evidence of EPCOR, or "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.

C. SUMMARY OF SETTLEMENT PROPOSAL AND PROPOSAL FOR ISSUES NOT COMPLETELY SETTLED

Summary of Settlement Proposal:

In reaching this partial settlement, the Parties have been guided by the Filing Requirements For Electricity Distribution Rate Applications – 2022 Edition for 2023 Rate Applications, dated April 18, 2022, the Approved Issues List and the Report of the OEB titled *Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach* dated October 18, 2012 (RRFE).

The Parties have reached a complete, partial or no settlement on the aspects of the Approved Issues List as summarized below in Table A.

Table A – Issues List Summary and Settlement Status

	ISSUE	**STATUS**
1.1	**Capital**	**No Settlement**
1.2	**OM&A**	**No Settlement**
2.0	**Revenue Requirement**	
	2.1 Are all elements of the revenue requirement reasonable, and have they been appropriately determined in accordance with OEB policies and practices?	**No Settlement**
	2.2 Has the revenue requirement been accurately determined based on these elements?	**No Settlement**
3.0	**Load Forecast, Cost Allocation and Rate Design**	
	3.1 Are the proposed load and customer forecast including the application of Conservation and Demand Management savings, loss factors, and resulting billing determinants appropriate, and to the extent applicable, are they an appropriate reflection of the energy and demand requirements of EPCOR Electricity Distribution Ontario Inc.'s customers?	**No Settlement**
	3.2 Are the proposed cost allocation methodology, allocations, and revenue-to-cost rations, appropriate?	**Complete Settlement**

	3.3 Are EPCOR Electricity Distribution Ontario Inc.'s proposals, including the proposed fixed/variable splits, for rate design appropriate?	**Partial Settlement**
	3.4 Are the proposed Retail Transmission Service Rates and Low Voltage rates appropriate?	**Complete Settlement**
	3.5 Are the Specific Service Charges, Retail Service Charges, and Pole Attachment Charge appropriate?	**Complete Settlement**
4.0	**Accounting**	
	4.1 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?	**No Settlement**
	4.2 Are EPCOR Electricity Distribution Ontario Inc.'s proposals for deferral and variance accounts, including the balances in the existing accounts and their disposition, requests for discontinuation of accounts, requests for establishment of new accounts and the continuation of existing accounts, appropriate?	**Partial Settlement**
5.0	**Other**	
	5.1 Is the proposed effective date (i.e. January 1, 2023) for 2023 rates appropriate?	**No Settlement**

This Settlement Proposal, including all Appendices, represents the evidence and the settlement between the Parties at the time of filing the Settlement Proposal, together with updates to the cost of capital arising from the OEB's October 20, 2022 letter announcing the 2023 cost of capital parameters; and the OEB's Regulated Price Plan update issued October 20, 2022. However, the Parties note that some evidence may need to be further updated as a result of the OEB's determination of the unsettled issues later in this proceeding.

The purpose of including the updated Revenue Requirement Work Form (RRWF), Chapter 2 Appendices, the DVA Continuity Schedule and proposed tariff is to establish the application data as updated to the end of the settlement process. Since there is not a complete settlement, there is no agreement that the values included within, and the resulting rates and bill impacts, are reasonable or appropriate.

Proposal for Issues not completely settled:

Due their complexity, importance, and interrelated nature, the Parties agree that the unsettled and partially settled issues would be most efficiently disposed of by way of an oral hearing.

SETTLEMENT BY ISSUE

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

1.0 PLANNING

1.1 **Capital**

Is the level of planned capital expenditures appropriate and is the rationale for planning and pacing choices appropriate and adequately explained, giving due consideration to:

- *customer feedback and preferences*
- *productivity*
- *benchmarking of costs*
- *reliability and service quality*
- *impact on distribution rates*
- *trade-offs with OM&A spending*
- *government-mandated obligations*
- *the objectives of EPCOR Electricity Distribution Ontario Inc. and its customers*
- *the distribution system plan*
- *the business plan*

No Settlement: The Parties have been unable to reach a settlement on this issue.

1.2 OM&A

Is the level of planned OM&A expenditures appropriate and is the rationale for planning choices appropriate and adequately explained, giving due consideration to:

- *customer feedback and preferences*
- *productivity*
- *benchmarking of costs*
- *reliability and service quality*
- *impact on distribution rates*
- *trade-offs with capital spending*
- *government-mandated obligations*
- *the objectives of EPCOR Electricity Distribution Ontario Inc. and its customers*
- *the distribution system plan*
- *the business plan*

No Settlement: The parties have been unable to reach a settlement on this issue.

2.0 REVENUE REQUIREMENT

2.1 *Are all elements of the revenue requirement reasonable, and have they been appropriately determined in accordance with OEB policies and practices?*

2.2 *Has the revenue requirement been accurately determined based on these elements?*

No Settlement: The Parties have been unable to reach a settlement on these issues.

3.0 LOAD FORECAST, COST ALLOCATION AND RATE DESIGN

3.1 Are the proposed load and customer forecast including the application of Conservation and Demand Management savings, loss factors, and resulting billing determinants appropriate, and to the extent applicable, are they an appropriate reflection of the energy and demand requirements of EPCOR Electricity Distribution Ontario Inc.'s customers?

Partial Settlement: With the exception of the loss factor calculation, there is no agreement on the appropriate load and customer forecast including the application of Conservation and Demand Management savings.

Although the Parties do agree with EPCOR's loss factor calculation for the purposes of setting rates, this does not preclude intervenors from proposing targets, plans or studies associated with EPCOR's loss factors in the course of a hearing.

Evidence:

Application: Exhibit 1.2.3; Exhibit 3; Exhibit 8.10

OEB Staff Clarification Questions: Question-13

IRRs: 1-Staff-1; 3-Staff-37 through 3-Staff-4; 3-SEC-30; 3-SEC-31; 3-VECC-15 through 3-VECC-23; 8-Staff-67; 8-SEC-46, 8-VECC-48

Clarification Responses: SEC-4

Chapter 2 Appendices updated for this Settlement Proposal:
Appendix 2-IB Load Forecast Analysis; Appendix 2-R Loss Factor Calculation

Appendices to this Settlement Proposal:
EEDO_2023 Load Forecast Model_20221205

Supporting Parties: SEC and VECC.
Parties Taking No Position: SBUA and ED.

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

Complete Settlement: Subject to updates required to implement the OEB's decision on the unsettled or partially settled issues, the parties accept that EPCOR's cost allocation methodology, allocations, and revenue-to-cost ratios are appropriate.

The Parties note, that in terms of the load profiles used, while there is an agreement to use the demand allocators proposed by EPCOR for the purpose of settlement as they are reasonable, there is no agreement that the methodology used to derive the values is appropriate.

Evidence:

Application: Section 1.2.7, Exhibit 3, Exhibit 7

OEB Staff Clarification Questions: Question-14

IRRs: 1-Staff-1; 7-Staff-62 through 7-Staff-64; 7-SBUA-4; 7-SBUA-5; 7-VECC-39 through 7-VECC-47

Clarification Responses: VECC-57

Chapter 2 Appendices updated for this Settlement Proposal: None

Appendices to this Settlement Proposal:
Appendix B – Updated 2023 Bill Impacts;
Appendix C – Updated 2023 Proposed Tariff of Rates and Charges

Supporting Parties: SEC and VECC.
Parties Taking No Position: SBUA and ED.

3.3 Are EPCOR Electricity Distribution Ontario Inc.'s proposals, including the proposed fixed/variable splits, for rate design appropriate?

Partial Settlement: Subject to updates required to implement the OEB's decision on the unsettled or partially settled issues and the potential need for rate mitigation, the Parties agree that EPCOR's proposals for rate design, including the proposed fixed/variable splits, are appropriate.

Evidence:

Application: Exhibit 1.2.7; Exhibit 8.1

IRRs: 1-Staff-1; 8-Staff-65 through 8-Staff-67; 8-VECC-48 through 8-VECC-51;

Clarification Responses: None

Chapter 2 Appendices updated for this Settlement Proposal: None

Appendices to this Settlement Proposal:
Appendix B – Updated 2023 Bill Impacts;
Appendix C – Updated 2023 Proposed Tariff of Rates and Charges

Supporting Parties: SEC and VECC.
Parties Taking No Position: SBUA and ED.

3.4 Are the proposed Retail Transmission Service Rates and Low Voltage Service Rates appropriate?

Complete Settlement: The Parties agree that the Retail Transmission Service Rates (RTSRs) are appropriate. As part of this Settlement Proposal, EPCOR has updated its evidence with respect to the Low Voltage Service Rates (see enclosed Appendix E – Updated Low Voltage Rates Calculation). On the basis of this revised evidence, the Parties agree that the updated Low Voltage Service Rates are appropriate.

Evidence:

Application: Exhibit 8.2 Retail Transmission Service Rates (RTSRs); Exhibit 8.7 Low Voltage Service Rates

OEB Staff Clarification Questions: None

IRRs: 1-Staff-1; 8-Staff-66; 8-VECC-50

Clarification Responses: None

Chapter 2 Appendices updated for this Settlement Proposal: Appendix 2-ZA Com Exp. Forecast; Appendix 2-ZB Cost of Power

Appendices to this Settlement Proposal: Appendix B – Updated 2023 Bill Impacts; Appendix C – Updated 2023 Proposed Tariff of Rates and Charges

Supporting Parties: SEC and VECC.
Parties Taking No Position: SBUA and ED.

3.5 Are the Specific Service Charges, Retail Service Charges, and Pole Attachment Charge appropriate?

Complete Settlement: The Parties agree that EPCOR's proposed Specific Service Charges are appropriate. As part of this Settlement Proposal, EPCOR has updated its evidence with respect to the Retail Service Charges and Pole Attachment Charge with the most current data (see enclosed Appendix C – Updated 2023 Proposed Tariff of Rates and Charges). On the basis of this revised evidence, the Parties agree that the updated Retail Service Charges and Pole Attachment Charge are appropriate.

Evidence:

Application: Exhibit 8.5 and 8.6;

OEB Staff Clarification Questions: None

IRRs: None

Clarification Responses: VECC_56

Chapter 2 Appendices updated for this Settlement Proposal: None

Appendices to this Settlement Proposal:
Appendix C – Updated 2023 Proposed Tariff of Rates and Charges

Supporting Parties: SEC and VECC.
Parties Taking No Position: SBUA and ED.

4.0 ACCOUNTING

4.1 *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?*

No Settlement: The parties have been unable to reach a settlement on this issue.

4.2 *Are EPCOR Electricity Distribution Ontario Inc.'s proposals for deferral and variance accounts, including the balances in the existing accounts and their disposition, requests for new accounts, requests for discontinuation of accounts, and the continuation of existing accounts, appropriate?*

Partial Settlement: Subject to the exceptions noted immediately below, the Parties agree that EPCOR's proposals for disposition of Group 1, LRAMVA and the updated Group 2 deferral and variance accounts, including the balances in the existing accounts, are appropriate. See enclosed Appendix F – Updated Group 2 DVA Balances for Disposition.

For further clarity, as part of the interrogatory process, EPCOR agreed to make a number of adjustments to the DVA balances *(principal balances shown below)*:

	Account	Name	Original Application	Settlement	Variance	Staff IR	Comment
1	1508	Customer Choice Initiative Costs	$8,500	$0	$8,500	9-Staff-74	Materiality
2	1508	Icon F&G Meter Disposal	$512,493	$512,493	$0	9-Staff-73	Carrying Charges Adjustment
3	1508	Energy East Consultation Costs	$2,275	$0	$2,275	9-Staff-74	Materiality
4	1508	LPP Variance	-$2,217	$0	-$2,217	9-Staff-74	Materiality
5	1508	Foregone Revenues from Postponing Rate Implementation	$0	-$17,475	$17,475	Settlement	Correction
6	1509	COVID-19 Deferral Account	$40,600	$0	$40,600	9-Staff-75/Settlement	Materiality
7	1557	Meter Cost Deferral Account (MIST Meters)	$250,901	$250,901	$0	9-Staff-77	Rate Class Reallocation
8	1595	Disposition and Recovery/Refund of Regulatory Balances (2018)	$33,898	$0	$33,898	9-Staff-86	Timing (must wait another year)
		Total	**$846,449**	**$745,919**	**$100,530**		

Exceptions:

- The Parties did not reach an agreement with respect to the appropriate disposition period for the proposed deferral and variance accounts and their applicable interest calculation, which is contingent on the OEB's approved effective dates for new rates. In addition, the Parties did not reach an agreement on the continuation or discontinuation of the deferral and variance accounts.

- The Parties do not agree that EPCOR's proposed disposition of Acct 1508 Other Regulatory Assets – OEB Cost Assessment Variance Account (Group 2) should be approved.

- The Parties do not agree that EPCOR's proposed establishment of the Non-Utility Billing Variance Account and Recovery of Income Taxes Deferral Account should be approved.

Evidence:

Application: Exhibit 1.2.8; Exhibit 9

OEB Staff Clarification Questions: None

IRRs: 1-Staff-1; 9-Staff-68 through 9-Staff-87; 9-SEC-47 through 9-SEC-49; 9-VECC-52 through 9-VECC-55

Clarification Responses: **9-Staff-104**

Chapter 2 Appendices updated for this Settlement Proposal: None

Appendices to this Settlement Proposal:
Appendix B – Updated 2023 Bill Impacts;
Appendix C – Updated 2023 Proposed Tariff of Rates and Charges
Appendix F – Updated Group 2 DVA Balances for Disposition
EEDO_2023 DVA_Continuity_Schedule_20221209

Supporting Parties: SEC and VECC.
Parties Taking No Position: SBUA and ED**.**

5.0 OTHER

5.1 *Is the proposed effective date (i.e. January 1, 2023) for 2023 rates appropriate?*

No Settlement: On September 14, 2022, EPCOR amended its application to request an effective date of October 1, 2023. EPCOR proposes that its first IRM rate adjustment after rates are set in this proceeding would be effective January 1, 2024.

The Parties have been unable to reach a settlement on this issue.

EB-2022-0028

EPCOR ELECTRICITY DISTRIBUTION ONTARIO INC.

SETTLEMENT PROPOSAL

Appendix A – Revised Revenue Requirement Work Form

[redacted]

Revenue Requirement Workform (RRWF) for 2022 Filers

Version 1.00

Utility Name	EPCOR Electricity Distribution Ontario Inc.
Service Territory	
Assigned EB Number	EB-2022-0028
Name and Title	Tim Hesselink, Senior Manager, Regulatory Affairs
Phone Number	705-445-1800 ext. 2274
Email Address	thesselink@epcor.com
Test Year	2023
Bridge Year	2022
Last Rebasing Year	2013

The RRWF has been enhanced commencing with 2017 rate applications to provide estimated base distribution rates. The enhanced RRWF is not intended to replace a utility's formal rate generator model which should continue to be the source of the proposed rates as well as the final ones at the conclusion of the proceeding. The load forecasting addition made to this model is intended to be demonstrative only and does not replace the information filed in the utility's application. In an effort to minimize the incremental work required from utilities, the cost allocation and rate design additions to this model do in fact replace former appendices that were required to be filed as part of the cost of service (Chapter 2) filing requirements.

While this model has been provided in Excel format and is required to be filed with the applications, the onus remains on the applicant to ensure the accuracy of the data and the

[redacted]

Revenue Requirement Workform (RRWF) for 2022 Filers

Notes:

(1)	Pale green cells represent inputs
(2)	Pale green boxes at the bottom of each page are for additional notes
(3)	Pale yellow cells represent drop-down lists
(4)	***Please note that this model uses MACROS. Before starting, please ensure that macros have been enabled.***
(5)	***Completed versions of the Revenue Requirement Work Form are required to be filed in working Microsoft Excel format.***

[redacted]

[redacted]

Data Input [1]

		Initial Application	(2)	Adjustments	Interrogatory Responses	(6)	Adjustments	Per Board Decision	
1	**Rate Base**								
	Gross Fixed Assets (average)	$42,620,963		($255,198)	$ 42,365,765			$42,365,765	
	Accumulated Depreciation (average)	($11,515,826)	(5)	$16,453	($11,499,373)			($11,499,373)	
	Allowance for Working Capital:								
	Controllable Expenses	$6,555,915			$ 6,555,915			$6,555,915	
	Cost of Power	$35,065,966		$863,736	$ 35,929,701			$35,929,701	
	Working Capital Rate (%)	7.50%	(9)	0.00%	7.50%	(9)			(9)
2	**Utility Income**								
	Operating Revenues:								
	Distribution Revenue at Current Rates	$8,209,408		($5,347)	$8,204,062				
	Distribution Revenue at Proposed Rates	$9,416,486		$110,932	$9,527,418				
	Other Revenue:								
	Specific Service Charges	$75,000		$0	$75,000				
	Late Payment Charges	$69,000		$0	$69,000				
	Other Distribution Revenue								
	Other Income and Deductions	$648,010		$4,390	$652,400				
	Total Revenue Offsets	$792,010	(7)	$4,390	$796,400				
	Operating Expenses:								
	OM+A Expenses	$6,530,315			$ 6,530,315			$6,530,315	
	Depreciation/Amortization	$1,688,100		($19,349)	$ 1,668,751			$1,668,751	
	Property taxes								
	Other expenses	$25,600			25600			$25,600	
3	**Taxes/PILs**								
	Taxable Income:								
	Adjustments required to arrive at taxable income	($1,185,616)	(3)	$0	($1,185,616)				
	Utility Income Taxes and Rates:								
	Income taxes (not grossed up)	$ -		$0	$ -				
	Income taxes (grossed up)	$ -			$ -				
	Federal tax (%)	0.00%		0.00%	0.00%				
	Provincial tax (%)	0.00%		0.00%	0.00%				
	Income Tax Credits				$ -				
4	**Capitalization/Cost of Capital**								
	Capital Structure:								
	Long-term debt Capitalization Ratio (%)	56.0%		0.00%	56.0%				
	Short-term debt Capitalization Ratio (%)	4.0%	(8)	0.00%	4.0%	(8)			(8)
	Common Equity Capitalization Ratio (%)	40.0%		0.00%	40.0%				
	Prefered Shares Capitalization Ratio (%)								
		100.0%			100.0%				
	Cost of Capital								
	Long-term debt Cost Rate (%)	3.98%		0.00%	3.98%				
	Short-term debt Cost Rate (%)	1.17%		3.62%	4.79%				
	Common Equity Cost Rate (%)	8.66%		0.70%	9.36%				
	Prefered Shares Cost Rate (%)								

Notes:

General Data inputs are required on Sheets 3. Data from Sheet 3 will automatically complete calculations on sheets 4 through 9 (Rate Base through Revenue Requirement). Sheets 4 through 9 do not require any inputs except for notes that the Applicant may wish to enter to support the results. Pale green cells are available on sheets 4 through 9 to enter both footnotes beside key cells and the related text for the notes at the bottom of each sheet.

(1) All inputs are in dollars ($) except where inputs are individually identified as percentages (%)

(2) Data in column E is for Application as originally filed. For updated revenue requirement as a result of interrogatory responses, technical or settlement conferences, etc., use column M and Adjustments in column I

(3) Net of addbacks and deductions to arrive at taxable income.

(4) Average of Gross Fixed Assets at beginning and end of the Test Year

(5) Average of Accumulated Depreciation at the beginning and end of the Test Year. Enter as a negative amount.

(6) Select option from drop-down list by clicking on cell M12. This column allows for the application update reflecting the end of discovery or Argument-in-Chief. Also, the outcome of any Settlement Process can be reflected.

(7) Input total revenue offsets for deriving the base revenue requirement from the service revenue requirement

(8) 4.0% unless an Applicant has proposed or been approved for another amount.

(9) The default Working Capital Allowance factor is **7.5%** (of Cost of Power plus controllable expenses), per the letter issued by the Board on June 3, 2015. Alternatively, a WCA factor based on lead-lag study, with supporting rationale could be provided.

[redacted]

[redacted]

Rate Base and Working Capital

Rate Base

Line No.	Particulars		Initial Application	Adjustments	Interrogatory Responses	Adjustments	Per Board Decision
1	Gross Fixed Assets (average)	(2)	$42,620,963	($255,198)	$42,365,765	$ -	$42,365,765
2	Accumulated Depreciation (average)	(2)	($11,515,826)	$16,453	($11,499,373)	$ -	($11,499,373)
3	Net Fixed Assets (average)	(2)	$31,105,137	($238,746)	$30,866,392	$ -	$30,866,392
4	Allowance for Working Capital	(1)	$3,121,641	$64,780	$3,186,421	($3,186,421)	$ -
5	**Total Rate Base**		$34,226,778	($173,965)	$34,052,813	($3,186,421)	$30,866,392

(1) Allowance for Working Capital - Derivation

Line No.	Particulars		Initial Application	Adjustments	Interrogatory Responses	Adjustments	Per Board Decision
6	Controllable Expenses		$6,555,915	$ -	$6,555,915	$ -	$6,555,915
7	Cost of Power		$35,065,966	$863,736	$35,929,701	$ -	$35,929,701
8	Working Capital Base		$41,621,881	$863,736	$42,485,617	$ -	$42,485,617
9	Working Capital Rate %	(1)	7.50%	0.00%	7.50%	-7.50%	0.00%
10	Working Capital Allowance		$3,121,641	$64,780	$3,186,421	($3,186,421)	$ -

Notes

(1) Some Applicants may have a unique rate as a result of a lead-lag study. The default rate for 2021 cost of service applications is 7.5%, per the letter issued by the Board on June 3, 2015.

(2) Average of opening and closing balances for the year.

[redacted]

Revenue Requirement Workform (RRWF) for 2022 Filers

Utility Income

Line No.	Particulars		Initial Application	Adjustments	Interrogatory Responses	Adjustments	Per Board Decision
	Operating Revenues:						
1	Distribution Revenue (at Proposed Rates)		$9,416,486	$110,932	$9,527,418	$ -	$9,527,418
2	Other Revenue	(1)	$792,010	$4,390	$796,400	$ -	$796,400
3	Total Operating Revenues		$10,208,496	$115,322	$10,323,818	$ -	$10,323,818
	Operating Expenses:						
4	OM+A Expenses		$6,530,315	$ -	$6,530,315	$ -	$6,530,315
5	Depreciation/Amortization		$1,688,100	($19,349)	$1,668,751	$ -	$1,668,751
6	Property taxes		$ -	$ -		$ -	
7	Capital taxes		$ -	$ -	$ -	$ -	$ -
8	Other expense		$25,600	$ -	$25,600	$ -	$25,600
9	Subtotal (lines 4 to 8)		$8,244,016	($19,349)	$8,224,667	$ -	$8,224,667
10	Deemed Interest Expense		$778,865	$45,350	$824,214	($121,819)	$702,396
11	Total Expenses (lines 9 to 10)		$9,022,880	$26,001	$9,048,881	($121,819)	$8,927,062
12	**Utility income before income taxes**		$1,185,616	$89,322	$1,274,937	$121,819	$1,396,756
13	Income taxes (grossed-up)		$ -	$ -	$ -	$ -	$ -
14	**Utility net income**		$1,185,616	$89,322	$1,274,937	$121,819	$1,396,756

Notes

Other Revenues / Revenue Offsets

Note	Particulars	Initial Application	Adjustments	Interrogatory Responses	Adjustments	Per Board Decision
(1)	Specific Service Charges	$75,000	$ -	$75,000		$75,000
	Late Payment Charges	$69,000	$ -	$69,000		$69,000
	Other Distribution Revenue	$ -		$ -		$ -
	Other Income and Deductions	$648,010	$4,390	$652,400		$652,400
	Total Revenue Offsets	$792,010	$4,390	$796,400	$ -	$796,400

[redacted]

Taxes/PILs

Line No.	Particulars	Application	Interrogatory Responses	Per Board Decision
	Determination of Taxable Income			
1	Utility net income before taxes	$1,185,616	$1,274,937	$1,069,212
2	Adjustments required to arrive at taxable utility income	($1,185,616)	($1,185,616)	($1,185,616)
3	Taxable income	$ -	$89,322	($116,404)
	Calculation of Utility income Taxes			
4	Income taxes	$ -	$ -	$ -
6	Total taxes	$ -	$ -	$ -
7	Gross-up of Income Taxes	$ -	$ -	$ -
8	Grossed-up Income Taxes	$ -	$ -	$ -
9	PILs / tax Allowance (Grossed-up Income taxes + Capital taxes)	$ -	$ -	$ -
10	Other tax Credits	$ -	$ -	$ -
	Tax Rates			
11	Federal tax (%)	0.00%	0.00%	0.00%
12	Provincial tax (%)	0.00%	0.00%	0.00%
13	Total tax rate (%)	0.00%	0.00%	0.00%

Notes

Revenue Requirement Workform (RRWF) for 2022 Filers

Capitalization/Cost of Capital

Line No.	Particulars	Capitalization Ratio		Cost Rate	Return
		Initial Application			
		(%)	($)	(%)	($)
	Debt				
1	Long-term Debt	56.00%	$19,166,996	3.98%	$762,846
2	Short-term Debt	4.00%	$1,369,071	1.17%	$16,018
3	**Total Debt**	60.00%	$20,536,067	3.79%	$778,865
	Equity				
4	Common Equity	40.00%	$13,690,711	8.66%	$1,185,616
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	40.00%	$13,690,711	8.66%	$1,185,616
7	**Total**	100.00%	$34,226,778	5.74%	$1,964,480
		Interrogatory Responses			
		(%)	($)	(%)	($)
	Debt				
1	Long-term Debt	56.00%	$19,069,575	3.98%	$758,969
2	Short-term Debt	4.00%	$1,362,113	4.79%	$65,245
3	**Total Debt**	60.00%	$20,431,688	4.03%	$824,214
	Equity				
4	Common Equity	40.00%	$13,621,125	9.36%	$1,274,937
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	40.00%	$13,621,125	9.36%	$1,274,937
7	**Total**	100.00%	$34,052,813	6.16%	$2,099,152
		Per Board Decision			
		(%)	($)	(%)	($)
	Debt				
8	Long-term Debt	56.00%	$17,285,179	3.98%	$687,950
9	Short-term Debt	4.00%	$1,234,656	1.17%	$14,445
10	**Total Debt**	60.00%	$18,519,835	3.79%	$702,396
	Equity				
11	Common Equity	40.00%	$12,346,557	8.66%	$1,069,212
12	Preferred Shares	0.00%	$ -	0.00%	$ -
13	**Total Equity**	40.00%	$12,346,557	8.66%	$1,069,212
14	**Total**	100.00%	$30,866,392	5.74%	$1,771,607

Notes

[redacted]

Revenue Requirement Workform (RRWF) for 2022 Filers

Revenue Deficiency/Sufficiency

Line No.	Particulars	Initial Application: At Current Approved Rates	Initial Application: At Proposed Rates	Interrogatory Responses: At Current Approved Rates	Interrogatory Responses: At Proposed Rates	Per Board Decision: At Current Approved Rates	Per Board Decision: At Proposed Rates
1	Revenue Deficiency from Below		$1,207,078		$1,323,357		$995,812
2	Distribution Revenue	$8,209,408	$8,209,408	$8,204,062	$8,204,062	$8,204,062	$8,531,606
3	Other Operating Revenue Offsets - net	$792,010	$792,010	$796,400	$796,400	$796,400	$796,400
4	**Total Revenue**	$9,001,418	$10,208,496	$9,000,462	$10,323,818	$9,000,462	$10,323,818
5	Operating Expenses	$8,244,016	$8,244,016	$8,224,667	$8,224,667	$8,224,667	$8,224,667
6	Deemed Interest Expense	$778,865	$778,865	$824,214	$824,214	$702,396	$702,396
8	**Total Cost and Expenses**	$9,022,880	$9,022,880	$9,048,881	$9,048,881	$8,927,062	$8,927,062
9	**Utility Income Before Income Taxes**	($21,462)	$1,185,616	($48,419)	$1,274,937	$73,399	$1,396,756
10	Tax Adjustments to Accounting Income per 2013 PILs model	($1,185,616)	($1,185,616)	($1,185,616)	($1,185,616)	($1,185,616)	($1,185,616)
11	**Taxable Income**	($1,207,078)	$ -	($1,234,035)	$89,322	($1,112,216)	$211,140
12	Income Tax Rate	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
13	**Income Tax on Taxable Income**	$ -	$ -	$ -	$ -	$ -	$ -
14	**Income Tax Credits**	$ -	$ -	$ -	$ -	$ -	$ -
15	**Utility Net Income**	($21,462)	$1,185,616	($48,419)	$1,274,937	$73,399	$1,396,756
16	**Utility Rate Base**	$34,226,778	$34,226,778	$34,052,813	$34,052,813	$30,866,392	$30,866,392
17	Deemed Equity Portion of Rate Base	$13,690,711	$13,690,711	$13,621,125	$13,621,125	$12,346,557	$12,346,557
18	Income/(Equity Portion of Rate Base)	-0.16%	8.66%	-0.36%	9.36%	0.59%	11.31%
19	Target Return - Equity on Rate Base	8.66%	8.66%	9.36%	9.36%	8.66%	8.66%
20	Deficiency/Sufficiency in Return on Equity	-8.82%	0.00%	-9.72%	0.00%	-8.07%	2.65%
21	Indicated Rate of Return	2.21%	5.74%	2.28%	6.16%	2.51%	6.80%
22	Requested Rate of Return on Rate Base	5.74%	5.74%	6.16%	6.16%	5.74%	5.74%
23	Deficiency/Sufficiency in Rate of Return	-3.53%	0.00%	-3.89%	0.00%	-3.23%	1.06%
24	Target Return on Equity	$1,185,616	$1,185,616	$1,274,937	$1,274,937	$1,069,212	$1,069,212
25	Revenue Deficiency/(Sufficiency)	$1,207,078	$ -	$1,323,357	$ -	$995,812	$327,544
26	**Gross Revenue Deficiency/(Sufficiency)**	$1,207,078 (1)		$1,323,357 (1)		$995,812 (1)	

Notes:

(1) Revenue Deficiency/Sufficiency divided by (1 - Tax Rate)

[redacted]

[redacted]

Revenue Requirement

Line No.	Particulars	Application		Interrogatory Responses		Per Board Decision	
1	OM&A Expenses	$6,530,315		$6,530,315		$6,530,315	
2	Amortization/Depreciation	$1,688,100		$1,668,751		$1,668,751	
3	Property Taxes	$ -					
5	Income Taxes (Grossed up)	$ -		$ -		$ -	
6	Other Expenses	$25,600		$25,600		$25,600	
7	Return						
	Deemed Interest Expense	$778,865		$824,214		$702,396	
	Return on Deemed Equity	$1,185,616		$1,274,937		$1,069,212	
8	**Service Revenue Requirement (before Revenues)**	$10,208,496		$10,323,818		$9,996,274	
9	Revenue Offsets	$792,010		$796,400		$ -	
10	**Base Revenue Requirement (excluding Tranformer Owership Allowance credit adjustment)**	$9,416,486		$9,527,418		$9,996,274	
11	Distribution revenue	$9,416,486		$9,527,418		$9,527,418	
12	Other revenue	$792,010		$796,400		$796,400	
13	**Total revenue**	$10,208,496		$10,323,818		$10,323,818	
14	**Difference (Total Revenue Less Distribution Revenue Requirement before Revenues)**	$ -	(1)	$ -	(1)	$327,544	(1)

Summary Table of Revenue Requirement and Revenue Deficiency/Sufficiency

	Application	Interrogatory Responses	Δ% (2)	Per Board Decision	Δ% (2)
Service Revenue Requirement	$10,208,496	$10,323,818	**1.13%**	$9,996,274	#####
Grossed-Up Revenue Deficiency/(Sufficiency)	$1,207,078	$1,323,357	**9.63%**	$995,812	#####
Base Revenue Requirement (to be recovered from Distribution Rates)	$9,416,486	$9,527,418	**1.18%**	$9,996,274	#####
Revenue Deficiency/(Sufficiency) Associated with Base Revenue Requirement	$1,207,078	$1,323,357	**9.63%**	$ -	#####

Notes

(1) Line 11 - Line 8

(2) Percentage Change Relative to Initial Application

[redacted]

[redacted]

Load Forecast Summary

This spreadsheet provides a summary of the customer and load forecast on which the test year revenue requirement is derived. The amounts serve as the denominators for deriving the rates to recover the test year revenue requirement for purposes of this RRWF.

The information to be input is inclusive of any adjustments to kWh and kW to reflect the impacts of CDM programs up to and including CDM programs planned to be executed in the test year. i.e., the load forecast adjustments determined in **Appendix 2-I** should be incorporated into the entries. The inputs should correspond with the summary of the Load Forecast for the Test Year in **Appendix 2-IB** and in Exhibit 3 of the application.

Appendix 2-IB is still required to be filled out, as it also provides a year-over-year variance analysis of demand growth andf trends from historical actuals to the Bridge and Test Year forecasts.

Stage in Process: Interrogatory Responses

	Customer Class	**Initial Application**			**Interrogatory Responses**			**Per Board Decision**		
	Input the name of each customer class.	**Customer / Connections** Test Year average or mid-year	**kWh** Annual	**kW/kVA** (1) Annual	**Customer / Connections** Test Year average or mid-year	**kWh** Annual	**kW/kVA** (1) Annual	**Customer / Connections** Test Year average or mid-year	**kWh** Annual	**kW/kVA** (1) Annual
1	Residential	17,012	137,646,072		17,012	137,612,684				
2	GS<50kW	1,833	44,991,441		1,833	44,847,586				
3	GS>50kW	127		325,120	127		324,247			
4	Streetlighting	3,318		3,496	3,318		3,496			
5	USL	30	396,233		30	396,233				
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8										
9										
10										
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19										
20										
	Total		**183,033,746**	**328,616**		**182,856,503**	**327,743**		**-**	**-**

Notes:

(1) Input kW or kVA for those customer classes for which billing is based on demand (kW or kVA) versus energy consumption (kWh)

[redacted]

[redacted]

Cost Allocation and Rate Design

This spreadsheet replaces **Appendix 2-P** and provides a summary of the results from the Cost Allocation spreadsheet, and is used in the determination of the class revenue requirement and, hence, ultimately, the determination of rates from customers in all classes to recover the revenue requirement.

Stage in Application Process: ***Interrogatory Responses***

A) Allocated Costs

	Name of Customer Class [3] From Sheet 10. Load Forecast	Costs Allocated from Previous Study [1]	%	Allocated Class Revenue Requirement [1] (7A)	%
1	Residential	$ 5,552,711	68.76%	$ 7,105,487	68.83%
2	GS<50kW	$ 1,192,782	14.77%	$ 1,436,144	13.91%
3	GS>50kW	$ 1,104,816	13.68%	$ 1,675,196	16.23%
4	Streetlighting	$ 219,370	2.72%	$ 98,445	0.95%
5	USL	$ 5,432	0.07%	$ 8,545	0.08%
6					
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8					
9					
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11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
	Total	$ 8,075,110	100.00%	**$ 10,323,818**	100.00%
			Service Revenue Requirement (from Sheet 9)	**$ 10,323,818.10**	

(1) Class Allocated Revenue Requirement, from Sheet O-1, Revenue to Cost || RR, row 40, from the Cost Allocation Study in this application. This excludes costs in deferral and variance accounts. For Embedded Distributors, Account 4750 - Low Voltage (LV) Costs are also excluded.

(2) Host Distributors - Provide information on any embedded distributor(s) as a separate class, if applicable. If embedded distributors are billed in a General Service class, include the allocated costs and revenues of the embedded distributor(s) in the applicable class, and also complete Appendix 2-Q.

(3) Customer Classes - If these differ from those in place in the previous cost allocation study, modify the customer classes to match the proposal in the current application as closely as possible.

B) Calculated Class Revenues

	Name of Customer Class	Load Forecast (LF) X current approved rates (7B)	LF X current approved rates X (1+d) (7C)	LF X Proposed Rates (7D)	Miscellaneous Revenues (7E)
1	Residential	$ 5,560,750	$ 6,457,727	$ 6,474,169	$ 577,167
2	GS<50kW	$ 1,193,525	$ 1,386,047	$ 1,386,047	$ 97,391
3	GS>50kW	$ 1,225,151	$ 1,422,774	$ 1,555,889	$ 106,540
4	Streetlighting	$ 219,204	$ 254,562	$ 103,513	$ 14,622
5	USL	$ 5,432	$ 6,308	$ 7,801	$ 679
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7					
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9					
10					
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12					
13					
14					
15					
16					
17					
18					
19					
20					
	Total	$ 8,204,062	$ 9,527,418	$ 9,527,418	$ 796,400

(4) In columns 7B to 7D, LF means Load Forecast of Annual Billing Quantities (i.e., customers or connections, as applicable X 12 months, and kWh, kW or kVA as applicable. Revenue quantities should be net of the Transformer Ownership Allowance for applicable customer classes. Exclude revenues from rate adders and rate riders.

(5) Columns 7C and 7D - Column Total should equal the Base Revenue Requirement for each.

(6) Column 7C - The OEB-issued cost allocation model calculates "1+d" on worksheet O-1, cell C22. "d" is defined as Revenue Deficiency/Revenue at Current Rates.

(7) Column 7E - If using the OEB-issued cost allocation model, enter Miscellaneous Revenues as it appears on worksheet O-1, row 19,

C) Rebalancing Revenue-to-Cost Ratios

	Name of Customer Class	Previously Approved Ratios Most Recent Year: 2013 %	Status Quo Ratios (7C + 7E) / (7A) %	Proposed Ratios (7D + 7E) / (7A) %	Policy Range %
1	Residential	101.90%	99.01%	99.24%	85 - 115
2	GS<50kW	94.10%	103.29%	103.29%	80 - 120
3	GS>50kW	95.90%	91.29%	99.24%	80 - 120
4	Streetlighting	120.00%	273.44%	120.00%	80 - 120
5	USL	120.00%	81.77%	99.24%	80 - 120
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9					
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19					
20					

(8) Previously Approved Revenue-to-Cost (R/C) Ratios - For most applicants, the most recent year would be the third year (at the latest) of the Price Cap IR period. For example, if the applicant, rebased in 2012 with further adjustments to move within the range over two years, the Most Recent Year would be 2015. However, the ratios in 2015 would be equal to those after the adjustment in 2014.

(9) Status Quo Ratios - The OEB-issued cost allocation model provides the Status Quo Ratios on Worksheet O-1. The Status Quo means "Before Rebalancing".

(10) Ratios shown in red are outside of the allowed range. Applies to both Tables C and D.

(D) ***Proposed Revenue-to-Cost Ratios*** [11]

	Name of Customer Class	Proposed Revenue-to-Cost Ratio			Policy Range
		Test Year	Price Cap IR Period		
		2022	2023	2024	
1	Residential	99.24%	99.24%	99.24%	85 - 115
2	GS<50kW	103.29%	103.29%	103.29%	80 - 120
3	GS>50kW	99.24%	99.24%	99.24%	80 - 120
4	Streetlighting	120.00%	120.00%	120.00%	80 - 120
5	USL	99.24%	99.24%	99.24%	80 - 120
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(11) The applicant should complete Table D if it is applying for approval of a revenue-to-cost ratio in 2021 that is outside of the OEB's policy range for any customer class. Table D will show that the distributor is likely to enter into the 2022 and 2023 Price Cap IR models, as necessary. For 2022 and 2023, enter the planned revenue-to-cost ratios that will be "Change" or "No Change" in 2019 (in the current Revenue/Cost Ratio Adjustment Workform, Worksheet C1.1 'Decision - Cost Revenue Adjustment, column d), and enter TBD for class(es) that will be entered as 'Rebalance'.

[redacted]

Revenue Requirement Workform (RRWF) for 2022 Filers

Rate Design and Revenue Reconciliation

This sheet replaces Appendix 2-V, and provides a simplified model for calculating the standard monthly and voluemtric rates based on the allocated class revenues and fixed/variable split resulting from the cost allocation study and rate design and as proposed by the applicant. However, the RRWF does not replace the rate generator model that an applicant distributor may use in support of its application. The RRWF provides a demonstrative check on the derivation of the revenue requirement and on the proposed base distribution rates to recover the revenue requirement, based on summary information from a more detailed rate generator model and other models that applicants use for cost allocation, load forecasting, taxes/PILs, etc.

Stage in Process: *Interrogatory Responses*

	Customer and Load Forecast					Class Allocated Revenues (From Sheet 11. Cost Allocation and Sheet 12. Residential Rate Design)			Fixed / Variable Splits [2] (Percentage to be entered as a fraction between 0 and 1)			Distribution Rates					Revenue Reconciliation		
	Customer Class (From sheet 10. Load Forecast)	Volumetric Charge Determinant	Customers / Connections	kWh	kW or kVA	Total Class Revenue Requirement	Monthly Service Charge	Volumetric	Fixed	Variable	Transformer Ownership Allowance [1] ($)	Monthly Service Charge Rate	No. of decimals	Volumetric Rate		No. of decimals	MSC Revenues	Volumetric revenues	Distribution Revenues less Transformer Ownership
1	Residential	kWh	17,012	137,612,684	-	$ 6,474,169	$ 6,474,169	$ -	100.00%	0.00%		$31.71	2	$0.0000	/kWh	4	$ 6,473,251.84	$ -	$ 6,473,251.84
2	GS<50kW	kWh	1,833	44,847,586	-	$ 1,386,047	$ 589,167	$ 796,879	42.51%	57.49%		$26.79		$0.0178	/kWh		$ 589,167.47	$ 798,287.0245	$ 1,387,454.50
3	GS>50kW	kW	127	-	324,247	$ 1,555,889	$ 167,501	$ 1,388,388	10.77%	89.23%	$ 111,000	$110.21		$4.6242	/kW		$ 167,500.65	$ 1,499,382.1076	$ 1,555,882.76
4	Streetlighting	kW	3,318	-	3,496	$ 103,513	$ 75,641	$ 27,871	73.07%	26.93%		$1.90		$7.9718	/kW		$ 75,641.36	$ 27,871.2772	$ 103,512.64
5	USL	kWh	30	396,233	-	$ 7,801	$ 288	$ 7,513	3.69%	96.31%		$0.80		$0.0190	/kWh		$ 288.00	$ 7,528.4323	$ 7,816.43
6			-	-	-												$ -	$ -	$ -
7			-	-	-												$ -	$ -	$ -
8			-	-	-												$ -	$ -	$ -
9			-	-	-												$ -	$ -	$ -
#			-	-	-												$ -	$ -	$ -
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Total Transformer Ownership Allowance $ 111,000

Total Distribution Revenues	$ 9,527,918.17
Base Revenue Requirement	$ 9,527,418.10
Difference	$ 500.07
% Difference	0.005%

Rates recover revenue requirement

Notes:

1 Transformer Ownership Allowance is entered as a positive amount, and only for those classes to which it applies.

2 The Fixed/Variable split, for each customer class, drives the "rate generator" portion of this sheet of the RRWF. Only the "fixed" fraction is entered, as the sum of the "fixed" and "variable" portions must sum to 100%. For a distributor that may set the Monthly Service Charge, the "fixed" ratio is calcutated as: [MSC x (average number of customers or connections) x 12 months] / (Class Allocated Revenue Requirement).

[redacted]

Revenue Requirement Workform (RRWF) for 2022 Filers

Tracking Form

The first row shown, labelled "Original Application", summarizes key statistics based on the data inputs into the RRWF. After the original application filing, the applicant provides key changes in capital and operating expenses, load forecasts, cost of capital, etc., as revised through the processing of the application. This could be due to revisions or responses to interrogatories. The last row shown is the most current estimate of the cost of service data reflecting the original application and any updates provided by the applicant distributor (for updated evidence, responses to interrogatories, undertakings, etc.)

Please ensure a Reference (Column B) and/or Item Description (Column C) is entered. Please note that unused rows will automatically be hidden and the PRINT AREA set when the PRINT BUTTON on Sheet 1 is activated.

(1) Short reference to evidence material (interrogatory response, undertaking, exhibit number, Board Decision, Code, Guideline, Report of the Board, etc.)

(2) Short description of change, issue, etc.

Summary of Proposed Changes

			Cost of Capital		Rate Base and Capital Expenditures			Operating Expenses			Revenue Requirement			
	Reference (1)	Item / Description (2)	Regulated Return on Capital	Regulated Rate of Return	Rate Base	Working Capital	Working Capital Allowance ($)	Amortization / Depreciation	Taxes/PILs	OM&A	Service Revenue Requirement	Other Revenues	Base Revenue Requirement	Grossed up Revenue Deficiency / Sufficiency
		Original Application	$ 1,964,480	5.74%	$ 34,226,778	$ 41,621,881	$ 3,121,641	$ 1,688,100	$ -	$ 6,530,315	$ 10,208,496	$ 792,010	$ 9,416,486	$ 1,207,078
1	3-Staff-41 Load Forecast	Load Forecast & COP Update	$ 1,965,422	5.74%	$ 34,243,180	$ 41,840,567	$ 3,138,043	$ 1,688,100	$ -	$ 6,530,315	$ 10,209,437	$ 792,010	$ 9,417,427	$ 1,213,366

EB-2022-0028

EPCOR ELECTRICITY DISTRIBUTION ONTARIO INC.

SETTLEMENT PROPOSAL

Appendix B – Revised Bill Impacts

[redacted]

[redacted]

The bill comparisons below must be provided for typical customers and consumption levels. Bill impacts must be provided for residential customers consuming 750 kWh per month and general service customers consuming 2,000 kWh per month and having a monthly demand of less than 50 kW. Include bill comparisons for Non-RPP (retailer) as well. **To assess the combined effects of the shift to fixed rates and other bill impacts associated with changes in the cost of distribution service, applicants are to include a total bill impact for a residential customer at the distributor's 10th consumption percentile (In other words, 10% of a distributor's residential customers consume at or less than this level of consumption on a monthly basis). Refer to section 3.2.3 of the Chapter 3 Filing Requirements For Electricity Distribution Rate Applications.**

For certain classes where one or more customers have unique consumption and demand patterns and which may be significantly impacted by the proposed rate changes, the distributor must show a typical comparison, and provide an explanation.

Note:
1. For those classes that are not eligible for the RPP price, the weighted average price including Class B GA through end of May 2017 of $0.1036/kWh (IESO's Monthly Market Report for May 2017, page 22) has been used to represent the cost of power. For those classes on a retailer contract, applicants should enter the contract price (plus GA) for a more accurate estimate. Changes to the cost of power can be made directly on the bill impact table for the specific class.
2. Please enter the applicable billing determinant (e.g. number of connections or devices) to be applied to the monthly service charge for unmetered rate classes in column N. If the monthly service charge is applied on a per customer basis, enter the number "1". Distributors should provide the number of connections or devices reflective of a typical customer in each class.

Note that cells with the highlighted color shown to the left indicate quantities that are loss adjusted.

Table 1

RATE CLASSES / CATEGORIES ***(eg: Residential TOU, Residential Retailer)***	**Units**	**RPP? Non-RPP Retailer? Non-RPP Other?**	**Current Loss Factor** **(eg: 1.0351)**	**Proposed Loss Factor**	**Consumption (kWh)**	**Demand kW (if applicable)**	**RTSR Demand or Demand-Interval?**	**Billing Determinant Applied to Fixed Charge for Unmetered Classes (e.g. # of devices/connections).**
RESIDENTIAL SERVICE CLASSIFICATION	**kWh**	RPP	1.071	1.0602	750		CONSUMPTION	
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	**kWh**	RPP	1.071	1.0602	2,000		CONSUMPTION	
GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION	**kW**	Non-RPP (Other)	1.071	1.0602	86,000	250	DEMAND	
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	**kWh**	Non-RPP (Other)	1.071	1.0602	150		CONSUMPTION	1
STREET LIGHTING SERVICE CLASSIFICATION	**kW**	Non-RPP (Other)	1.071	1.0602	15,000	100	DEMAND	1,000
RESIDENTIAL SERVICE CLASSIFICATION	**kWh**	Non-RPP (Retailer)	1.071	1.0602	750		CONSUMPTION	
RESIDENTIAL SERVICE CLASSIFICATION	**kWh**	RPP	1.071	1.0602	256		CONSUMPTION	
GENERAL SERVICE LESS THAN 50 kW SERVICE CLASSIFICATION	**kWh**	Non-RPP (Retailer)	1.071	1.0602	2,000		CONSUMPTION	
Add additional scenarios if required								
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Table 2

RATE CLASSES / CATEGORIES *(eg: Residential TOU, Residential Retailer)*	Units	Sub-Total						Total	
		A		B		C		Total Bill	
		$	%	$	%	$	%	$	%
RESIDENTIAL SERVICE CLASSIFICATION - RPP	kWh	$ 5.58	20.7%	$ 8.58	25.6%	$ 8.54	19.0%	$ 8.61	7.2%
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION - RPP	kWh	$ 11.72	21.8%	$ 18.72	26.7%	$ 18.66	19.3%	$ 18.79	6.3%
GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION - Non-RPP (Other)	kW	$ 415.34	41.1%	$ 753.94	66.0%	$ 763.24	31.7%	$ 748.27	5.3%
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION - Non-RPP (Other)	kWh	$ 1.29	50.8%	$ 1.56	40.4%	$ 1.55	26.5%	$ 1.56	6.9%
STREET LIGHTING SERVICE CLASSIFICATION - Non-RPP (Other)	kW	$ (1,927.27)	-33.7%	$ (1,792.89)	-31.2%	$ (1,790.06)	-29.2%	$ (2,042.68)	-22.9%
RESIDENTIAL SERVICE CLASSIFICATION - Non-RPP (Retailer)	kWh	$ 5.58	20.7%	$ 7.29	21.4%	$ 7.26	15.9%	$ 7.31	5.7%
RESIDENTIAL SERVICE CLASSIFICATION - RPP	kWh	$ 5.58	20.7%	$ 6.60	22.4%	$ 6.59	19.7%	$ 6.66	11.2%
GENERAL SERVICE LESS THAN 50 kW SERVICE CLASSIFICATION - Non-RPP (Retailer)	kWh	$ 11.72	21.8%	$ 15.28	21.3%	$ 15.22	15.5%	$ 15.31	4.8%

Customer Class:	**RESIDENTIAL SERVICE CLASSIFICATION**
RPP / Non-RPP:	**RPP**
Consumption	**750** **kWh**
Demand	**-** **kW**
Current Loss Factor	**1.0710**
Proposed/Approved Loss Factor	**1.0602**

	Current OEB-Approved			**Proposed**			**Impact**	
	Rate ($)	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	$ 27.24	1	$ 27.24	$ 31.71	1	$ 31.71	$ 4.47	16.41%
Distribution Volumetric Rate	$ -	750	$ -	$ -	750	$ -	$ -	
Fixed Rate Riders	$ (0.25)	1	$ (0.25)	$ 0.86	1	$ 0.86	$ 1.11	-444.00%
Volumetric Rate Riders	$ -	750	$ -	$ -	750	$ -	$ -	
Sub-Total A (excluding pass through)			**$ 26.99**			**$ 32.57**	**$ 5.58**	**20.67%**
Line Losses on Cost of Power	$ 0.0926	53	$ 4.93	$ 0.0926	45	$ 4.18	$ (0.75)	-15.21%
Total Deferral/Variance Account Rate Riders	$ -	750	$ -	$ 0.0026	750	$ 1.95	$ 1.95	
CBR Class B Rate Riders	$ -	750	$ -	$ -	750	$ -	$ -	
GA Rate Riders	$ -	750	$ -	$ -	750	$ -	$ -	
Low Voltage Service Charge	$ 0.0016	750	$ 1.20	$ 0.0041	750	$ 3.08	$ 1.88	156.25%
Smart Meter Entity Charge (if applicable)	$ 0.42	1	$ 0.42	$ 0.42	1	$ 0.42	$ -	0.00%
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Volumetric Rate Riders		750	$ -	$ (0.0001)	750	$ (0.08)	$ (0.08)	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 33.54**			**$ 42.12**	**$ 8.58**	**25.58%**
RTSR - Network	$ 0.0091	803	$ 7.31	$ 0.0092	795	$ 7.32	$ 0.01	0.08%
RTSR - Connection and/or Line and Transformation Connection	$ 0.0051	803	$ 4.10	$ 0.0051	795	$ 4.06	$ (0.04)	-1.01%
Sub-Total C - Delivery (including Sub-Total B)			**$ 44.95**			**$ 53.49**	**$ 8.54**	**19.01%**
Wholesale Market Service Charge (WMSC)	$ 0.0045	803	$ 3.61	$ 0.0045	795	$ 3.58	$ (0.04)	-1.01%
Rural and Remote Rate Protection (RRRP)	$ 0.0007	803	$ 0.56	$ 0.0007	795	$ 0.56	$ (0.01)	-1.01%
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
TOU - Off Peak	$ 0.0740	488	$ 36.08	$ 0.0740	488	$ 36.08	$ -	0.00%
TOU - Mid Peak	$ 0.1020	128	$ 13.01	$ 0.1020	128	$ 13.01	$ -	0.00%
TOU - On Peak	$ 0.1510	135	$ 20.39	$ 0.1510	135	$ 20.39	$ -	0.00%
Total Bill on TOU (before Taxes)			**$ 118.84**			**$ 127.34**	**$ 8.50**	**7.15%**
HST	13%		$ 15.45	13%		$ 16.55	$ 1.11	7.15%
Ontario Electricity Rebate	11.7%		$ (13.90)	11.7%		$ (14.90)	$ (0.99)	
Total Bill on TOU			**$ 120.38**			**$ 129.00**	**$ 8.61**	**7.15%**

Customer Class:	GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION
RPP / Non-RPP:	RPP
Consumption	2,000 kWh
Demand	- kW
Current Loss Factor	1.0710
Proposed/Approved Loss Factor	1.0602

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 23.07	1	$ 23.07	$ 26.79	1	$ 26.79	$ 3.72	16.12%
Distribution Volumetric Rate	$ 0.0153	2000	$ 30.60	$ 0.0178	2000	$ 35.60	$ 5.00	16.34%
Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Volumetric Rate Riders	$ -	2000	$ -	$ 0.0015	2000	$ 3.00	$ 3.00	
Sub-Total A (excluding pass through)			**$ 53.67**			**$ 65.39**	**$ 11.72**	**21.84%**
Line Losses on Cost of Power	$ 0.0926	142	$ 13.15	$ 0.0926	120	$ 11.15	$ (2.00)	-15.21%
Total Deferral/Variance Account Rate Riders	$ -	2,000	$ -	$ 0.0026	2,000	$ 5.20	$ 5.20	
CBR Class B Rate Riders	$ -	2,000	$ -	$ -	2,000	$ -	$ -	
GA Rate Riders	$ -	2,000	$ -	$ -	2,000	$ -	$ -	
Low Voltage Service Charge	$ 0.0014	2,000	$ 2.80	$ 0.0034	2,000	$ 6.80	$ 4.00	142.86%
Smart Meter Entity Charge (if applicable)	$ 0.42	1	$ 0.42	$ 0.42	1	$ 0.42	$ -	0.00%
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Volumetric Rate Riders		2,000	$ -	$ (0.0001)	2,000	$ (0.20)	$ (0.20)	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 70.04**			**$ 88.76**	**$ 18.72**	**26.73%**
RTSR - Network	$ 0.0083	2,142	$ 17.78	$ 0.0084	2,120	$ 17.81	$ 0.03	0.18%
RTSR - Connection and/or Line and Transformation Connection	$ 0.0042	2,142	$ 9.00	$ 0.0042	2,120	$ 8.91	$ (0.09)	-1.01%
Sub-Total C - Delivery (including Sub-Total B)			**$ 96.82**			**$ 115.48**	**$ 18.66**	**19.27%**
Wholesale Market Service Charge (WMSC)	$ 0.0045	2,142	$ 9.64	$ 0.0045	2,120	$ 9.54	$ (0.10)	-1.01%
Rural and Remote Rate Protection (RRRP)	$ 0.0007	2,142	$ 1.50	$ 0.0007	2,120	$ 1.48	$ (0.02)	-1.01%
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
TOU - Off Peak	$ 0.0740	1,300	$ 96.20	$ 0.0740	1,300	$ 96.20	$ -	0.00%
TOU - Mid Peak	$ 0.1020	340	$ 34.68	$ 0.1020	340	$ 34.68	$ -	0.00%
TOU - On Peak	$ 0.1510	360	$ 54.36	$ 0.1510	360	$ 54.36	$ -	0.00%
Total Bill on TOU (before Taxes)			**$ 293.45**			**$ 311.99**	**$ 18.55**	**6.32%**
HST	13%		$ 38.15	13%		$ 40.56	$ 2.41	6.32%
Ontario Electricity Rebate	11.7%		$ (34.33)	11.7%		$ (36.50)	$ (2.17)	
Total Bill on TOU			**$ 297.26**			**$ 316.05**	**$ 18.79**	**6.32%**

Customer Class:	GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION
RPP / Non-RPP:	Non-RPP (Other)
Consumption	86,000 kWh
Demand	250 kW
Current Loss Factor	1.0710
Proposed/Approved Loss Factor	1.0602

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 110.21	1	$ 110.21	$ 110.21	1	$ 110.21	$ -	0.00%
Distribution Volumetric Rate	$ 3.6042	250	$ 901.05	$ 4.6242	250	$ 1,156.05	$ 255.00	28.30%
Fixed Rate Riders	$ -	1	$ -	$ 89.44	1	$ 89.44	$ 89.44	
Volumetric Rate Riders	$ -	250	$ -	$ 0.2836	250	$ 70.90	$ 70.90	
Sub-Total A (excluding pass through)			**$ 1,011.26**			**$ 1,426.60**	**$ 415.34**	**41.07%**
Line Losses on Cost of Power	$ -	-	$ -	$ -	-	$ -	$ -	
Total Deferral/Variance Account Rate Riders	$ -	250	$ -	$ 1.0880	250	$ 272.00	$ 272.00	
CBR Class B Rate Riders	$ -	250	$ -	$ -	250	$ -	$ -	
GA Rate Riders	$ -	86,000	$ -	$ (0.0016)	86,000	$ (137.60)	$ (137.60)	
Low Voltage Service Charge	$ 0.5215	250	$ 130.38	$ 1.3608	250	$ 340.20	$ 209.83	160.94%
Smart Meter Entity Charge (if applicable)	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Volumetric Rate Riders		250	$ -	$ (0.0225)	250	$ (5.63)	$ (5.63)	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 1,141.64**			**$ 1,895.58**	**$ 753.94**	**66.04%**
RTSR - Network	$ 3.2679	250	$ 816.98	$ 3.2907	250	$ 822.68	$ 5.70	0.70%
RTSR - Connection and/or Line and Transformation Connection	$ 1.7842	250	$ 446.05	$ 1.7986	250	$ 449.65	$ 3.60	0.81%
Sub-Total C - Delivery (including Sub-Total B)			**$ 2,404.66**			**$ 3,167.90**	**$ 763.24**	**31.74%**
Wholesale Market Service Charge (WMSC)	$ 0.0045	92,106	$ 414.48	$ 0.0045	91,177	$ 410.30	$ (4.18)	-1.01%
Rural and Remote Rate Protection (RRRP)	$ 0.0007	92,106	$ 64.47	$ 0.0007	91,177	$ 63.82	$ (0.65)	-1.01%
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
Average IESO Wholesale Market Price	$ 0.1036	92,106	$ 9,542.18	$ 0.1036	91,177	$ 9,445.96	$ (96.22)	-1.01%
Total Bill on Average IESO Wholesale Market Price			**$ 12,426.04**			$ 13,088.23	**$ 662.19**	**5.33%**
HST	13%		$ 1,615.39	13%		$ 1,701.47	$ 86.08	5.33%
Ontario Electricity Rebate	11.7%		$ -	11.7%		$ -		
Total Bill on Average IESO Wholesale Market Price			**$ 14,041.43**			**$ 14,789.70**	**$ 748.27**	**5.33%**

Customer Class:	UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	
RPP / Non-RPP:	Non-RPP (Other)	
Consumption	150	kWh
Demand	-	kW
Current Loss Factor	1.0710	
Proposed/Approved Loss Factor	1.0602	

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 0.56	1	$ 0.56	$ 0.80	1	$ 0.80	$ 0.24	42.86%
Distribution Volumetric Rate	$ 0.0132	150	$ 1.98	$ 0.0190	150	$ 2.85	$ 0.87	43.94%
Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Volumetric Rate Riders	$ -	150	$ -	$ 0.0012	150	$ 0.18	$ 0.18	
Sub-Total A (excluding pass through)			**$ 2.54**			**$ 3.83**	**$ 1.29**	**50.79%**
Line Losses on Cost of Power	$ 0.1036	11	$ 1.10	$ 0.1036	9	$ 0.94	$ (0.17)	-15.21%
Total Deferral/Variance Account Rate Riders	$ -	150	$ -	$ 0.0026	150	$ 0.39	$ 0.39	
CBR Class B Rate Riders	$ -	150	$ -	$ -	150	$ -	$ -	
GA Rate Riders	$ -	150	$ -	$ (0.0016)	150	$ (0.24)	$ (0.24)	
Low Voltage Service Charge	$ 0.0014	150	$ 0.21	$ 0.0034	150	$ 0.51	$ 0.30	142.86%
Smart Meter Entity Charge (if applicable)	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Volumetric Rate Riders		150	$ -	$ (0.0001)	150	$ (0.02)	$ (0.02)	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 3.85**			**$ 5.41**	**$ 1.56**	**40.41%**
RTSR - Network	$ 0.0083	161	$ 1.33	$ 0.0084	159	$ 1.34	$ 0.00	0.18%
RTSR - Connection and/or Line and Transformation Connection	$ 0.0042	161	$ 0.67	$ 0.0042	159	$ 0.67	$ (0.01)	-1.01%
Sub-Total C - Delivery (including Sub-Total B)			**$ 5.86**			**$ 7.41**	**$ 1.55**	**26.49%**
Wholesale Market Service Charge (WMSC)	$ 0.0045	161	$ 0.72	$ 0.0045	159	$ 0.72	$ (0.01)	-1.01%
Rural and Remote Rate Protection (RRRP)	$ 0.0007	161	$ 0.11	$ 0.0007	159	$ 0.11	$ (0.00)	-1.01%
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
Average IESO Wholesale Market Price	$ 0.1036	150	$ 15.54	$ 0.1036	150	$ 15.54	$ -	0.00%
Total Bill on Average IESO Wholesale Market Price			**$ 22.49**			**$ 24.03**	**$ 1.54**	**6.87%**
HST	13%		$ 2.92	13%		$ 3.12	$ 0.20	6.87%
Ontario Electricity Rebate	11.7%		$ (2.63)	11.7%		$ (2.81)		
Total Bill on Average IESO Wholesale Market Price			**$ 22.78**			**$ 24.34**	**$ 1.56**	**6.87%**

Customer Class:	**STREET LIGHTING SERVICE CLASSIFICATION**
RPP / Non-RPP:	Non-RPP (Other)
Consumption	**15,000 kWh**
Demand	**100 kW**
Current Loss Factor	**1.0710**
Proposed/Approved Loss Factor	**1.0602**

	Current OEB-Approved			**Proposed**			**Impact**	
	Rate ($)	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	$ 4.03	1000	$ 4,030.00	$ 1.90	1000	$ 1,900.00	$ (2,130.00)	-52.85%
Distribution Volumetric Rate	$ 16.8079	100	$ 1,680.79	$ 7.9718	100	$ 797.18	$ (883.61)	-52.57%
Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Volumetric Rate Riders	$ -	100	$ -	$ 10.8634	100	$ 1,086.34	$ 1,086.34	
Sub-Total A (excluding pass through)			**$ 5,710.79**			**$ 3,783.52**	**$ (1,927.27)**	**-33.75%**
Line Losses on Cost of Power	$ -	-	$ -	$ -	-	$ -	$ -	
Total Deferral/Variance Account Rate Riders	$ -	100	$ -	$ 0.9544	100	$ 95.44	$ 95.44	
CBR Class B Rate Riders	$ -	100	$ -	$ -	100	$ -	$ -	
GA Rate Riders	$ -	15,000	$ -	$ (0.0016)	15,000	$ (24.00)	$ (24.00)	
Low Voltage Service Charge	$ 0.4031	100	$ 40.31	$ 1.0520	100	$ 105.20	$ 64.89	160.98%
Smart Meter Entity Charge (if applicable)	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Volumetric Rate Riders		100	$ -	$ (0.0195)	100	$ (1.95)	$ (1.95)	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 5,751.10**			**$ 3,958.21**	**$ (1,792.89)**	**-31.17%**
RTSR - Network	$ 2.4646	100	$ 246.46	$ 2.4818	100	$ 248.18	$ 1.72	0.70%
RTSR - Connection and/or Line and Transformation Connection	$ 1.3793	100	$ 137.93	$ 1.3904	100	$ 139.04	$ 1.11	0.80%
Sub-Total C - Delivery (including Sub-Total B)			**$ 6,135.49**			**$ 4,345.43**	**$ (1,790.06)**	**-29.18%**
Wholesale Market Service Charge (WMSC)	$ 0.0045	16,065	$ 72.29	$ 0.0045	15,903	$ 71.56	$ (0.73)	-1.01%
Rural and Remote Rate Protection (RRRP)	$ 0.0007	16,065	$ 11.25	$ 0.0007	15,903	$ 11.13	$ (0.11)	-1.01%
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
Average IESO Wholesale Market Price	$ 0.1036	16,065	$ 1,664.33	$ 0.1036	15,903	$ 1,647.55	$ (16.78)	-1.01%
Total Bill on Average IESO Wholesale Market Price			**$ 7,883.61**			**$ 6,075.93**	**$ (1,807.69)**	**-22.93%**
HST	13%		$ 1,024.87	13%		$ 789.87	$ (235.00)	-22.93%
Ontario Electricity Rebate	11.7%		$ -	11.7%		$ -		
Total Bill on Average IESO Wholesale Market Price			**$ 8,908.48**			**$ 6,865.80**	**$ (2,042.68)**	**-22.93%**

Customer Class:	RESIDENTIAL SERVICE CLASSIFICATION
RPP / Non-RPP:	Non-RPP (Retailer)
Consumption	750 kWh
Demand	- kW
Current Loss Factor	1.0710
Proposed/Approved Loss Factor	1.0602

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 27.24	1	$ 27.24	$ 31.71	1	$ 31.71	$ 4.47	16.41%
Distribution Volumetric Rate	$ -	750	$ -	$ -	750	$ -	$ -	
Fixed Rate Riders	$ (0.25)	1	$ (0.25)	$ 0.86	1	$ 0.86	$ 1.11	-444.00%
Volumetric Rate Riders	$ -	750	$ -	$ -	750	$ -	$ -	
Sub-Total A (excluding pass through)			**$ 26.99**			**$ 32.57**	**$ 5.58**	**20.67%**
Line Losses on Cost of Power	$ 0.1036	53	$ 5.52	$ 0.1036	45	$ 4.68	$ (0.84)	-15.21%
Total Deferral/Variance Account Rate Riders	$ -	750	$ -	$ 0.0026	750	$ 1.95	$ 1.95	
CBR Class B Rate Riders	$ -	750	$ -	$ -	750	$ -	$ -	
GA Rate Riders	$ -	750	$ -	$ (0.0016)	750	$ (1.20)	$ (1.20)	
Low Voltage Service Charge	$ 0.0016	750	$ 1.20	$ 0.0041	750	$ 3.08	$ 1.88	156.25%
Smart Meter Entity Charge (if applicable)	$ 0.42	1	$ 0.42	$ 0.42	1	$ 0.42	$ -	0.00%
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Volumetric Rate Riders		750	$ -	$ (0.0001)	750	$ (0.08)	$ (0.08)	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 34.13**			**$ 41.42**	**$ 7.29**	**21.36%**
RTSR - Network	$ 0.0091	803	$ 7.31	$ 0.0092	795	$ 7.32	$ 0.01	0.08%
RTSR - Connection and/or Line and Transformation Connection	$ 0.0051	803	$ 4.10	$ 0.0051	795	$ 4.06	$ (0.04)	-1.01%
Sub-Total C - Delivery (including Sub-Total B)			**$ 45.53**			**$ 52.79**	**$ 7.26**	**15.93%**
Wholesale Market Service Charge (WMSC)	$ 0.0045	803	$ 3.61	$ 0.0045	795	$ 3.58	$ (0.04)	-1.01%
Rural and Remote Rate Protection (RRRP)	$ 0.0007	803	$ 0.56	$ 0.0007	795	$ 0.56	$ (0.01)	-1.01%
Standard Supply Service Charge								
Non-RPP Retailer Avg. Price	$ 0.1036	750	$ 77.70	$ 0.1036	750	$ 77.70	$ -	0.00%
Total Bill on Non-RPP Avg. Price			**$ 127.41**			**$ 134.62**	**$ 7.21**	**5.66%**
HST	13%		$ 16.56	13%		$ 17.50	$ 0.94	5.66%
Ontario Electricity Rebate	11.7%		$ (14.91)	11.7%		$ (15.75)		
Total Bill on Non-RPP Avg. Price			**$ 129.07**			**$ 136.37**	**$ 7.31**	**5.66%**

Customer Class: RESIDENTIAL SERVICE CLASSIFICATION
RPP / Non-RPP: RPP
Consumption 256 kWh
Demand - kW
Current Loss Factor 1.0710
Proposed/Approved Loss Factor 1.0602

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 27.24	1	$ 27.24	$ 31.71	1	$ 31.71	$ 4.47	16.41%
Distribution Volumetric Rate	$ -	256	$ -	$ -	256	$ -	$ -	
Fixed Rate Riders	$ (0.25)	1	$ (0.25)	$ 0.86	1	$ 0.86	$ 1.11	-444.00%
Volumetric Rate Riders	$ -	256	$ -	$ -	256	$ -	$ -	
Sub-Total A (excluding pass through)			**$ 26.99**			**$ 32.57**	**$ 5.58**	**20.67%**
Line Losses on Cost of Power	$ 0.0926	18	$ 1.68	$ 0.0926	15	$ 1.43	$ (0.26)	-15.21%
Total Deferral/Variance Account Rate Riders	$ -	256	$ -	$ 0.0026	256	$ 0.67	$ 0.67	
CBR Class B Rate Riders	$ -	256	$ -	$ -	256	$ -	$ -	
GA Rate Riders	$ -	256	$ -	$ -	256	$ -	$ -	
Low Voltage Service Charge	$ 0.0016	256	$ 0.41	$ 0.0041	256	$ 1.05	$ 0.64	156.25%
Smart Meter Entity Charge (if applicable)	$ 0.42	1	$ 0.42	$ 0.42	1	$ 0.42	$ -	0.00%
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Volumetric Rate Riders		256	$ -	$ (0.0001)	256	$ (0.03)	$ (0.03)	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 29.50**			**$ 36.11**	**$ 6.60**	**22.38%**
RTSR - Network	$ 0.0091	274	$ 2.50	$ 0.0092	271	$ 2.50	$ 0.00	0.08%
RTSR - Connection and/or Line and Transformation Connection	$ 0.0051	274	$ 1.40	$ 0.0051	271	$ 1.38	$ (0.01)	-1.01%
Sub-Total C - Delivery (including Sub-Total B)			**$ 33.40**			**$ 39.99**	**$ 6.59**	**19.74%**
Wholesale Market Service Charge (WMSC)	$ 0.0045	274	$ 1.23	$ 0.0045	271	$ 1.22	$ (0.01)	-1.01%
Rural and Remote Rate Protection (RRRP)	$ 0.0007	274	$ 0.19	$ 0.0007	271	$ 0.19	$ (0.00)	-1.01%
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
TOU - Off Peak	$ 0.0740	166	$ 12.31	$ 0.0740	166	$ 12.31	$ -	0.00%
TOU - Mid Peak	$ 0.1020	44	$ 4.44	$ 0.1020	44	$ 4.44	$ -	0.00%
TOU - On Peak	$ 0.1510	46	$ 6.96	$ 0.1510	46	$ 6.96	$ -	0.00%
Total Bill on TOU (before Taxes)			**$ 58.78**			**$ 65.36**	**$ 6.58**	**11.19%**
HST	13%		$ 7.64	13%		$ 8.50	$ 0.86	11.19%
Ontario Electricity Rebate	11.7%		$ (6.88)	11.7%		$ (7.65)	$ (0.77)	
Total Bill on TOU			**$ 59.55**			**$ 66.21**	**$ 6.66**	**11.19%**

Customer Class:	**GENERAL SERVICE LESS THAN 50 kW SERVICE CLASSIFICATION**
RPP / Non-RPP:	**Non-RPP (Retailer)**
Consumption	**2,000** kWh
Demand	**-** kW
Current Loss Factor	**1.0710**
Proposed/Approved Loss Factor	**1.0602**

	Current OEB-Approved			**Proposed**			**Impact**	
	Rate ($)	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	$ 23.07	1	$ 23.07	$ 26.79	1	$ 26.79	$ 3.72	16.12%
Distribution Volumetric Rate	$ 0.0153	2000	$ 30.60	$ 0.0178	2000	$ 35.60	$ 5.00	16.34%
Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Volumetric Rate Riders	$ -	2000	$ -	$ 0.0015	2000	$ 3.00	$ 3.00	
Sub-Total A (excluding pass through)			**$ 53.67**			**$ 65.39**	**$ 11.72**	**21.84%**
Line Losses on Cost of Power	$ 0.1036	142	$ 14.71	$ 0.1036	120	$ 12.47	$ (2.24)	-15.21%
Total Deferral/Variance Account Rate Riders	$ -	2,000	$ -	$ 0.0026	2,000	$ 5.20	$ 5.20	
CBR Class B Rate Riders	$ -	2,000	$ -	$ -	2,000	$ -	$ -	
GA Rate Riders	$ -	2,000	$ -	$ (0.0016)	2,000	$ (3.20)	$ (3.20)	
Low Voltage Service Charge	$ 0.0014	2,000	$ 2.80	$ 0.0034	2,000	$ 6.80	$ 4.00	142.86%
Smart Meter Entity Charge (if applicable)	$ 0.42	1	$ 0.42	$ 0.42	1	$ 0.42	$ -	0.00%
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Volumetric Rate Riders		2,000	$ -	$ (0.0001)	2,000	$ (0.20)	$ (0.20)	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 71.60**			**$ 86.88**	**$ 15.28**	**21.34%**
RTSR - Network	$ 0.0083	2,142	$ 17.78	$ 0.0084	2,120	$ 17.81	$ 0.03	0.18%
RTSR - Connection and/or Line and Transformation Connection	$ 0.0042	2,142	$ 9.00	$ 0.0042	2,120	$ 8.91	$ (0.09)	-1.01%
Sub-Total C - Delivery (including Sub-Total B)			**$ 98.38**			**$ 113.60**	**$ 15.22**	**15.48%**
Wholesale Market Service Charge (WMSC)	$ 0.0045	2,142	$ 9.64	$ 0.0045	2,120	$ 9.54	$ (0.10)	-1.01%
Rural and Remote Rate Protection (RRRP)	$ 0.0007	2,142	$ 1.50	$ 0.0007	2,120	$ 1.48	$ (0.02)	-1.01%
Standard Supply Service Charge								
Non-RPP Retailer Avg. Price	$ 0.1036	2,000	$ 207.20	$ 0.1036	2,000	$ 207.20	$ -	0.00%
Total Bill on Non-RPP Avg. Price			**$ 316.71**			**$ 331.83**	**$ 15.11**	**4.77%**
HST	13%		$ 41.17	13%		$ 43.14	$ 1.96	4.77%
Ontario Electricity Rebate	11.7%		$ (37.06)	11.7%		$ (38.82)		
Total Bill on Non-RPP Avg. Price			**$ 320.83**			**$ 336.14**	**$ 15.31**	**4.77%**

EB-2022-0028

EPCOR ELECTRICITY DISTRIBUTION ONTARIO INC.

SETTLEMENT PROPOSAL

Appendix C – Revised Tariff of Rates & Charges

EPCOR Electricity Distribution Ontario Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date October 1, 2023

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

EB-2022-0028

RESIDENTIAL SERVICE CLASSIFICATION

This classification refers to an account taking electricity at 750 volts or less where the electricity is used exclusively in a separate metered living accommodation. Customers shall be residing in single-dwelling units that consist of a detached house or one unit of a semi-detached, duplex, triplex or quadruplex house, with a residential zoning.
Separately metered dwellings within a town house complex or apartment building also qualify as residential customers. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	31.71
Rate Rider for Group 2 Accounts - effective until September 30, 2025	$	0.86
Smart Metering Entity Charge - effective until December 31, 2023	$	0.42
Low Voltage Service Rate	$/kWh	0.0041
Rate Rider for Disposition of Deferral/Variance Accounts - effective until September 30, 2025	$/kWh	0.0026
Rate Rider for Disposition of Capacity Based Recovery Account Applicable only for Class B Customers - effective until September 30, 2025	$/kWh	(0.0001)
Rate Rider for Disposition of Global Adjustment Account - Non RPP Customers - effective until September 30, 2025	$/kWh	(0.0016)
Retail Transmission Rate - Network Service Rate	$/kWh	0.0092
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0051

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	0.0007
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

EPCOR Electricity Distribution Ontario Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date October 1, 2023

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

EB-2022-0028

GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION

This classification applies to a non residential account taking electricity at 750 volts or less whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to the Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	26.79
Smart Metering Entity Charge - effective until December 31, 2023	$	0.42
Distribution Volumetric Rate	$/kWh	0.0178
Low Voltage Service Rate	$/kWh	0.0034
Rate Rider for Disposition of Deferral/Variance Accounts - effective until September 30, 2025	$/kWh	0.0026
Rate Rider for Disposition of Capacity Based Recovery Account Applicable only for Class B Customers - effective until September 30, 2025	$/kWh	(0.0001)
Rate Rider for Disposition of Global Adjustment Account - Non RPP Customers - effective until September 30, 2025	$/kWh	(0.0016)
Rate Rider for Group 2 Accounts - effective until September 30, 2025	$/kWh	0.0006
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) - effective until September 30, 2025	$/kWh	0.0009
Retail Transmission Rate - Network Service Rate	$/kWh	0.0084
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0042

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	0.0007
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

EPCOR Electricity Distribution Ontario Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date October 1, 2023

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EB-2022-0028

GENERAL SERVICE 50 TO 4,999 KW SERVICE CLASSIFICATION

This classification applies to a non residential account whose average monthly maximum demand used for billing purposes is equal to or greater than, or is forecast to be equal to or greater than, 50 kW but less than 5,000 kW. Class A and Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. 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 the Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	110.21
Rate Rider for Mist Meter Deferral Account - effective until September 30, 2025	$	89.44
Distribution Volumetric Rate	$/kW	4.6242
Low Voltage Service Rate	$/kW	1.3608
Rate Rider for Disposition of Deferral/Variance Accounts - effective until September 30, 2025	$/kW	0.7801
Rate Rider for Disposition of Capacity Based Recovery Account Applicable only for Class B Customers - effective until September 30, 2025	$/kW	(0.0225)
Rate Rider for Disposition of Deferral/Variance Accounts Applicable only for Non-Wholesale Market Participants - effective until September 30, 2025	$/kW	0.3079
Rate Rider for Disposition of Global Adjustment Account - Non RPP Customers - effective until September 30, 2025	$/kWh	(0.0016)

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Rate Rider for Group 2 Accounts - effective until September 30, 2025	$/kW	0.2372
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) - effective until September 30, 2025	$/kW	0.0464
Retail Transmission Rate - Network Service Rate	$/kW	3.2907
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.7986

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	0.0007
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

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UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

This classification applies to an account taking electricity at 750 volts or less whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW and the consumption is unmetered. Such connections include cable TV power packs, bus shelters, telephone booths, traffic lights, railway crossings, etc. The level of the consumption will be agreed to by the distributor and the customer, based on detailed manufacturer information/ documentation with regard to electrical consumption of the unmetered load or periodic monitoring of actual consumption. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to the Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	0.80
Distribution Volumetric Rate	$/kWh	0.0190
Low Voltage Service Rate	$/kWh	0.0034
Rate Rider for Disposition of Deferral/Variance Accounts - effective until September 30, 2025	$/kWh	0.0026
Rate Rider for Disposition of Capacity Based Recovery Account Applicable only for Class B Customers - effective until September 30, 2025	$/kWh	(0.0001)
Rate Rider for Disposition of Global Adjustment Account - Non RPP Customers - effective until September 30, 2025	$/kWh	(0.0016)
Rate Rider for Group 2 Accounts - effective until September 30, 2025	$/kWh	0.0014
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) - effective until September 30, 2025	$/kWh	(0.0002)
Retail Transmission Rate - Network Service Rate	$/kWh	0.0084
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0042

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	0.0007
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

EPCOR Electricity Distribution Ontario Inc.
TARIFF OF RATES AND CHARGES
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STREET LIGHTING SERVICE CLASSIFICATION

This classification applies to an account for roadway lighting with a Municipality, Regional Municipality, Ministry of Transportation and private roadway lighting, controlled by photo cells. The consumption for these customers will be based on the calculated connected load times the required lighting times established in the approved Ontario Energy Board street lighting load shape template. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to the Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per connection)	$	1.90
Distribution Volumetric Rate	$/kW	7.9718
Low Voltage Service Rate	$/kW	1.0520
Rate Rider for Disposition of Deferral/Variance Accounts - effective until September 30, 2025	$/kW	0.9544
Rate Rider for Disposition of Capacity Based Recovery Account Applicable only for Class B Customers - effective until September 30, 2025	$/kW	(0.0195)
Rate Rider for Disposition of Global Adjustment Account - Non RPP Customers - effective until September 30, 2025	$/kWh	(0.0016)
Rate Rider for Group 2 Accounts - effective until September 30, 2025	$/kW	(1.1204)
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) - effective until September 30, 2025	$/kW	11.9838
Retail Transmission Rate - Network Service Rate	$/kW	2.4818
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.3904

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	0.0007
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

EPCOR Electricity Distribution Ontario Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date October 1, 2023
This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2022-0028

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 the Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	4.55

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 the Ontario Energy Board approval, such as the Global Adjustment and the HST.

Customer Administration

Charge to certify cheque	$	15.00
Arrears certificate	$	15.00
Statement of account	$	15.00
Pulling post dated cheques	$	15.00
Duplicate invoices for previous billing	$	15.00
Account history	$	15.00
Credit reference/credit check (plus credit agency costs)	$	15.00
Returned cheque (plus bank charges)	$	15.00
Legal letter charge	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	15.00

EPCOR Electricity Distribution Ontario Inc.
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Special meter reads	$	30.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	30.00

Non-Payment of Account

Late payment - per month (effective annual rate 19.56% per annum or 0.04896% compounded daily)	%	1.50
Reconnection at meter - during regular hours	$	40.00
Reconnection at meter - after regular hours	$	185.00
Reconnection at pole - during regular hours	$	185.00
Reconnection at pole - after regular hours	$	415.00

Other

Service call - after regular hours	$	165.00
Specific charge for access to the power poles - $/pole/year (with the exception of wireless attachments)	$	36.05

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 the 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	$	104.24
Monthly Fixed Charge, per retailer	$	41.70
Monthly Variable Charge, per customer, per retailer	$/cust.	1.04
Distributor-consolidated billing monthly charge, per customer, per retailer	$/cust.	0.62
Retailer-consolidated billing monthly credit, per customer, per retailer	$/cust.	(0.62)
Service Transaction Requests (STR)		
Request fee, per request, applied to the requesting party	$	0.52
Processing fee, per request, applied to the requesting party	$	1.04
Request for customer information as outlined in Section 10.6.3 and Chapter 11 of the Retail Settlement Code directly to retailers and customers, if not delivered electronically through the Electronic Business Transaction (EBT) system, applied to the requesting party		
Up to twice a year	$	no charge
More than twice a year, per request (plus incremental delivery costs)	$	4.17
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)	$	2.08

EPCOR Electricity Distribution Ontario Inc.
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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	1.0602
Total Loss Factor - Primary Metered Customer	1.0496

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EPCOR ELECTRICITY DISTRIBUTION ONTARIO INC.

SETTLEMENT PROPOSAL

Appendix D – Responses to Pre-Settlement Clarification Questions

OEB Staff’s Pre-Settlement Clarification Questions
2023 Electricity Distribution Rates Application
EPCOR Electricity Distribution Ontario Inc.
EB-2022-0028
October 26, 2022

(Numbering follows from OEB Staff Interrogatory dated September 26, 2022)

1-Staff-89
Ref: 1-Staff-9

For the lease with the Town of Collingwood, please quantify the 2023 revenue requirement of treating the lease as an operating lease and also treating the lease as a finance lease.

EEDO Response:

The revenue requirement of treating the lease as an operating lease is estimated at $217,006 for the 2023 test year. This is estimated based on payments for January through September at contracted rates with October through December escalated by an estimated inflation factor of 3.55% as part of the lease clause.

The revenue requirement of treating the lease as a finance lease is estimated at $227,441 for the 2023 test year. This is estimated based on calculating the return on rate base of $55,611 plus depreciation of $171,830.

1-Staff-90
Assurance of Voluntary Compliance
Ref: OEB Letter dated August 22, 2022 re Assurance of Voluntary Compliance (AVC) OEB File No. EB-2022-0205

Preamble:

On August 22, 2022, the OEB accepted the AVC filed by EPCOR Electricity Distribution Ontario on August 18, 2022 related to an wrongful disconnection issue. Under the terms of the AVC, EPCOR Electricity Distribution Ontario will pay an administrative monetary penalty of $18,000 and make an additional payment of $3,000 to the social agency that runs the Low-income Energy Assistance Program (LEAP) in its service territory.

Question(s):

a) Please explain the source of funding needed for the above noted penalty and additional LEAP amounts.

EEDO Response:

This is a shareholder cost.

b) Please confirm whether EPCOR Electricity Distribution Ontario intents to include the penalty and/or additional LEAP amounts in the 2023 Test Year revenue requirements and recover them from ratepayers.

EEDO Response:

EEDO has not and does not intend to include the penalty and/or additional LEAP amounts in the 2023 test year revenue requirement.

2-Staff-91
Ref: 2-Staff-13
Chapter 2 Appendix 2-BA
Accounting Procedures Handbook, Article 510, p.15

In response to 2-Staff-13, it was indicated that the 2015 MIFRS opening net book value was reduced in error and that the main difference was due to Account 1995 – Contributions and Grants. However, there is an immaterial impact as the average useful life in Appendix 2-C for the account is nil.

Per the Accounting Procedures Handbook, upon transition to IFRS, the balance in Account 1995 should be transferred to Account 2440 – Deferred Revenues. In Appendix 2-BA, the 2013 CGAAP ending and 2014 CGAAP opening net book value in Account 1995 is $6,398,120. In Appendix 2-BA, the 2014 MIFRS opening net book value for Account 1995 is $0, however, opening net book value of Account 2440 – Deferred Revenues is also $0, with additions in the year of $351,231.

a) Upon transition to IFRS in 2014, please explain how the closing 2013 CGAAP Account 1995 balance was treated in the opening 2014 MIFRS fixed asset continuity schedule.

EEDO Response:

For the purpose of preparing the opening 2014 MIFRS balances, the closing 2013 CGAAP Account 1995 balance was netted against the fixed asset account the contribution & grant pertained to. This resulted in adjustments to the 1830/1835/1845/1850/1855 accounts.

b) Please explain how the associated amortization of contributions have been recorded in Appendix 2-BA and Appendix 2-C.

EEDO Response:

In Appendices 2-BA and 2-C the associated amortization of contributions received in 2013 and prior has been recorded in the account where the 1995 balance was netted against (1830/1835/1845/1850/1855). For contributions and grants received in 2014 and after, the amortization is presented in the deferred revenue (Account 2440).

2-Staff-92
Road Authority
Ref: 2-Staff-16, Historical Expenditures

Preamble:

EPCOR Electricity Distribution Ontario updated appendix 2-AA and divided the historical road authority spending and customer demand. It showed that there was no road authority spending from 2016 to 2021 and only a minimal amount forecasted for 2022.

Question(s):

a) Please explain how EPCOR Electricity Distribution Ontario forecasted the 2023 amount for road authority spending.

EEDO Response:

The minimal spending in 2022 and the amount in 2023 pertains to a project that was originally planned to be completed in 2022. This project has been mostly deferred into 2023 as a result of delays in the counterparty finalizing their design. The project cost was estimated based on the amount of work (10 poles with an underground section) required and costed based on comparable projects that have been completed.

b) Please provide the list of expected road authority projects in 2023 and provide any correspondence EPCOR Electricity Distribution Ontario had with the city on these projects.

EEDO Response:

The 2023 expected road authority project is for the Grey Road 19 roundabout. The employee who was liaising with the municipalities on this road authority project is no longer employed at EEDO and historical correspondence is not available. The engineering consultant engaged by EEDO has been in contact with the municipality on design and engineering of the project.

2-Staff-93
Customer Demand
Ref: 2-Staff-16, Historical Expenditures
Chapter 2 Appendices – 2-AB

Preamble:

EPCOR Electricity Distribution Ontario updated appendix 2-AA and divided the historical road authority spending and customer demand. It shows that the customer demand for 2023 is $324k and the customer demand contribution is $457k.

Question(s):

a) Please explain how the capital contribution can exceed the customer demand.

EEDO Response:

When revising the 2022 capital expenditure forecast and splitting out road authority and customer demanded projects, the 2022 spending associated with the road authority project was mostly deferred into 2023 with a corresponding reduction in 2023 customer demanded spending in order to keep overall 2023 capital expenditures whole.

This adjustment inadvertently resulted in the capital contribution exceeding the spending on the customer demanded work. EEDO expects the overall net capital expenditures for 2023 to remain the same.

b) The average net customer demand budget between 2013 to 2018 is $49k. The average net customer demand budget between 2019 to 2022 is $336k. Please explain the driver for the higher customer demand budget.

EEDO Response:

The drivers for the increase in average net customer demanded capital expenditures from 2019 to 2022 are:

1) An increase in customer demanded projects, specifically economic evaluations which have higher net capital expenditures associated with them.

2) Some projects have contributions yet to be fully received from customers and were inadvertently excluded from the 2022 forecast for customer contributions.

2-Staff-94
Historical Expenditure Clarification
Ref: 2-Staff-17, Historical Expenditures

Preamble:

EPCOR Electricity Distribution Ontario stated that if a project is delayed the project amount would be in the planned capital budget for 2 different years. It would appear that this would double count delayed projects.

Question(s):

a) Please update Chapter 2 appendices – 2-AB with the project cost in the planned capital budget year and not the budget of the year where the deferred project was completed.

EEDO Response:

Please see below for an updated Appendix 2-AB for the 2013-2017 period where double counted delayed projects have been removed.

Appendix 2-AB

Table 2 - Capital Expenditure Summary from Chapter 5 Consolidated

First year of Forecast Period: *2023*

CATEGORY	Historical Period (previous plan[1] & actual)														
	2013			2014			2015			2016			2017		
	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var
	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000		%
System Access	850,500	515,211	-39.4%	775,500	771,753	-0.5%	775,500	1,306,527	68.5%	768,753	1,998,181	159.9%	752,909	855,614	13.6%
System Renewal	1,050,708	614,162	-41.5%	1,179,656	967,938	-17.9%	1,234,386	789,973	-36.0%	1,694,155	1,229,086	-27.5%	2,115,500	2,166,866	2.4%
System Service	40,000	13,411	-66.5%	40,000	13,696	-65.8%	740,000	157,963	-78.7%	49,200	574,269	1067.2%	51,087	36,226	-29.1%
General Plant	382,000	237,698	-37.8%	505,000	387,068	-23.4%	220,000	133,386	-39.4%	621,150	508,391	-18.2%	626,334	459,192	-26.7%
TOTAL EXPENDITURE	2,323,208	1,380,482	-40.6%	2,500,156	2,140,455	-14.4%	2,969,886	2,387,849	-19.6%	3,133,258	4,309,927	37.6%	3,545,830	3,517,897	-0.8%
Capital Contributions	- 350,000	- 323,111	-7.7%	- 350,000	- 351,231	0.4%	- 350,000	- 745,573	113.0%	- 449,875	- 1,739,589	286.7%	- 449,875	- 527,957	17.4%
Net Capital Expenditures	1,973,208	1,057,371	-46.4%	2,150,156	1,789,224	-16.8%	2,619,886	1,642,276	-37.3%	2,683,383	2,570,338	-4.2%	3,095,955	2,989,941	-3.4%
System O&M	$1,945,300	$2,053,457	5.6%	$2,130,006	$2,169,113	1.8%	$2,230,665	$2,388,712	7.1%	$2,297,585	$2,482,131	8.0%	$2,517,407	$2,189,894	-13.0%

2-Staff-95
Cost of Pole Replacement
Ref: 2-Staff-18, Historical Expenditures
2-Staff-21, Number of Poles Being Replaced

Preamble:

EPCOR Electricity Distribution Ontario provided the number of poles replaced under system renewal in reference 1. Comparing the number of poles replaced and the total program budget in Chapter 2 Appendix 2-AA shows that the average cost to replace a pole was around $7,400 between 2013 to 2018. The average cost to replace a pole between 2019 to 2022 was $14,100.

Question(s):

a) Please explain the driver of the unit cost almost doubling.

EEDO Response:

Many of the poles in our 2023 plan are rear lot construction. This is driving our labour costs higher due to the extra person hours it will take to access back yards, climb poles to complete work and complete restoration of homeowners properties compared to being able to access with bucket trucks. We will being seeing higher contractor costs associated with these projects as well due to extra equipment and time that will be required to install port-a-holes and anchors as well as crane rentals for setting poles.

b) In reference 2, EPCOR Electricity Distribution Ontario plans to replace on average 110 poles/year, whereas in the past five years EPCOR Electricity Distribution Ontario replaced on average 134 poles/year. Please explain the lower planned replacements of poles.

EEDO Response:

Refer to 2-Staff 95a)

c) The average unit cost per pole in 2023 is $16,900 per pole. Please explain the higher unit cost forecast.

EEDO Response:

Refer to 2-Staff 95a)

d) The average unit cost per pole for the DSP period of 2023-2027 is $18,505 per pole. Please explain the higher unit cost forecast compared to previous periods.

EEDO Response:

Refer to 2-Staff 95a)

a) Has EPCOR Electricity Distribution Ontario changed its pole design standards for storm hardening?

EEDO Response:

EPCOR continues to use the USF Standards for pole design and would modify based on revisions to the standard.

2-Staff-96
Number of Poles Replaced
Ref: 2-Staff-21, Number of Poles Being Replaced

Preamble:

EPCOR Electricity Distribution Ontario states that it expects there to be approximately 463 poles left in poor or very poor condition by the end of the DSP period. This is significantly less than at the start of the DSP with 891 poles in poor or very poor condition.

Question(s):

a) Is EPCOR Electricity Distribution Ontario's long-term goal to remove all poles in poor or very poor condition? At the pace of the existing program, there would be no poles in poor condition by the end of the next DSP period.

EEDO Response:

The long term goal is to address all of the poles that are in poor to very poor condition. Whether this is completed by the end of the next DSP period will depend on a number of variables such as cost of material, other deficiencies found in EPCOR's system that would require attention as a priority (older U/G cables start to fail and need replacing), substation issues, system access projects, storms, etc..

2-Staff-97
Reliability
Ref: 2-Staff-25, Reliability

Preamble:

The table of defective equipment outages EPCOR Electricity Distribution Ontario provided does not include poles as a failure component.

Question(s):

a) Please confirm whether pole failure is included under defective equipment. If so, please confirm that no pole failures resulted in outages between 2017 to 2021.

EEDO Response:

Pole failure is currently not included under defective equipment. Pole failures are normally related to storm events or fallen trees.

b) Is EPCOR Electricity Distribution Ontario able to provide divide the tree contact cause code by "growth" and "fallen tree"? If so, please provide it.

EEDO Response:

This information is not available.

2-Staff-98
Stayner MS
Ref: 2-Staff-31, Stayner MS1 and M2

Preamble:

EPCOR Electricity Distribution Ontario provided the concurrent peak for the Stayner MS1 and MS2.

Question(s):

a) Please provide the top 5 concurrent peaks for Stayner MS1 and MS2 and the duration of each peak.

EEDO Response:

DATE	HOUR ENDING	MS2 (KW)	MS1 (KW)	TOTAL (KW)
6/27/2021	18:00	3,749.686	2,207.875	5,957.561
8/29/2021	17:00	3,742.509	2,204.710	5,947.219
6/27/2021	17:00	3,753.717	2,182.043	5,935.760
8/29/2021	18:00	3,684.526	2,226.297	5,910.823
6/6/2021	17:00	3,193.352	2,713.239	5,906.591

2-Staff-99
ArcGIS Pro
Ref: 2-SEC-26

Preamble:

SEC asked about the feasibility of migrating to ArcGIS Pro and replacing the underlying data model with Esri's Utility Network (UN) over two years instead of one. EPCOR Electricity Distribution Ontario replied that the work can be done in one year.

Question(s):

a) Please provide the cost to perform the migration to ArcGIS Pro and to replace the underlying data model with Esri's Utility Network separately.

EEDO Response:

The cost to perform the migration to ArcGIS Pro to avoid end of life for ArcMap is estimated to be $14k including Contingency and Overhead. The significant undertaking is the upgrade to the Utility Network model estimated at $494k including Contingency and Overhead. The adoption of the new UN data model is where EEDO will see most business benefits.

b) Is it feasible to split the work over two years to divide the project's capital cost?

EEDO Response:

Currently, the proposed migration to ArcGIS Pro in 2023 is due to the existing Esri's ArcMap software updates, including security patches, ceasing in 2024. The replacement of the underlying data model with Esri's Utility Network uses ArcGIS pro to edit and analyze the utility network data. Hence, the upgrade to the Utility Network model needs to happen at the same time as the migration to ArcGIS Pro.

EEDO has currently planned a combination of external and internal IT resources and business subject matter experts to develop and prioritize the business needs and requirements of the UN upgrade project over nine months in 2023. Further, a detailed scope of work with the Implementation vendor has been completed. To avoid any further potential disruptions and delays and to ensure the technical upgrade of ArcGIS Pro and Migration to UN are completed simultaneously, EEDO will plan to complete both projects in 2023 as originally submitted in the Business Case.

4-Staff-100
Shared Service Costs 2023 Test Year vs 2013 OEB-approved
Ref: 4-SEC-34, 4-Staff-43

Preamble:

In response to 4-SEC-34, EPCOR Electricity Distribution Ontario provided the following table for shared service costs:

$000	2013 appr.	2013 actual	2014 actual	2015 actual	2016 actual	2017 actual	2018 actual	2019 actual	2020 actual	2021 actual	2022 bridge	2023 test year
Collus PowerStream Solutions	1,071	975	1,144	1,068	694	-	-					
Service Fee	132	132	132	-	-	-	-					
Town of Collingwood	59	22	5	8	19	39	17					
Collingwood PUC	367	310	287	276	238	216	180					
Alectra	-	182	239	160	221	181	115					
Affiliate Shared Services								365	557	511	758	790
Corporate Shared Services							186	740	682	660	792	875
Total	**1,629**	**1,621**	**1,807**	**1,512**	**1,172**	**436**	**498**	**1,105**	**1,239**	**1,171**	**1,550**	**1,665**

In response to 4-Staff-43, EPCOR Electricity Distribution Ontario confirmed that the $1,665k total estimated shared service costs for 2023 are fully pertaining to the Administration and General portion in OM&A.

Question(s):

a) Please confirm if all cost amounts listed in the “2013 appr.” (and “2013 actual” to 2018 columns) in the table above are pertaining to the Administration and General portion in OM&A.

EEDO Response:

No, the 2013 approved as well as the 2013 actual to 2018 actual costs do not pertain solely to the General & Admin portion of OM&A, portions of the approved shared service costs relate to Operations & Maintenance and Billing & Collecting.

b) If the answer to a) is yes for the “2013 appr.” column, please answer the following questions:

   i. For IR 4-Staff-43 b) question, please confirm if the difference in shared service costs between 2023 Test Year and 2013 Approved, in amount of $36k ($1,665k - $1,629k = $36k), should be referred to as the increase in Administration and General costs attributable to shared services costs.

   ii. If the answer to part i above is yes, based on the information presented on pages 15 to 17 of Exhibit 4, there should be other factors (cost drivers) contributed to the total increase in Administration and General costs in OM&A (in amount of $1,235k). Please provide this information.

   iii. If the answer to part i above is no, please explain why.

EEDO Response:

N/A, answer to a) is no

c) If the answer to a) of this question is no for the 2013 amounts, please indicate which categories of OM&A are the cost amounts pertaining to. Then with the 2013 approved amounts pertaining to Administration and General, please re-calculate the contribution of share service cost increase in the total Administration and General increase. Please provide similar reconciliation as instructed in i to iii above.

EEDO Response:

Of the 2013 approved amounts in shared services, they can be broken out to the following categories of OM&A

	Operations & Maintenance	Billing & Collecting	General & Admin	Total
Collus Powerstream Solutions	247	280	544	1,071
Service Fee	-	-	132	132
Town of Collingwood	59	-	-	59

Collingwood PUC	244	58	65	367
Total	**550**	**338**	**741**	**1,629**

A reconciliation of cost drivers contributing to the increase in General & Administration costs is provided below:

2013T General & Admin	**1,380**
Shared services in G&A removed	(741)
Increase in EPCOR shared services	1,665
Inflation	285
Other	26
2023T General & Admin	**2,615**

i) No, the difference in shared service costs from 2013 to 2023 does not explain the increase in General and Administration costs.

ii) N/A

iii) See above for reconciliation of 2013T G&A to 2023T G&A

5-Staff-101
Ref: 5-Staff-56
2023 Cost of Capital Parameters

On October 20, 2022, the OEB issued a letter to all rate-regulated utilities and parties involved in cost of service based application, announcing updated cost of capital parameters for cost-based rates that have an effective date commencing in 2023. As approved by the OEB, the new deemed long-term (LT) debt rate for 2023 rate applications is 4.88%.[1]

The following table has been prepared by OEB staff based on the information that EPCOR Electricity Distribution Ontario provided in Exhibit 5 (and Chapter 2 Appendix 2-OB) of the application and the historical and current OEB Cost of Capital Parameters.

Date of Issuance		**Term (years)**	**Principal**	**Rate EEDO Applied in Application**	**OEB Deemed LT Debt Rate (most current at the time of issuance of debt)**
3-Dec-18	Actual	30	$8,100,000	4.30%	4.13%
1-Dec-20	Actual	30	$2,020,000	2.88%	2.85%
15-Dec-21	Actual	30	$2,000,000	3.41%	3.49%
31-Dec-22	Forecasted	30	$1,200,000	5.25%	4.88%
31-Dec-23	Forecasted	30	$1,200,000	5.03%	4.88%

The 2023 deemed LT debt rate of 4.88% is lower than the two estimated debt rates that EPCOR Electricity Distribution Ontario has applied to its affiliated LT debt instruments forecasted to be issued in December 2022 and December 2023. In the preamble to interrogatory 5-Staff-56, OEB staff documented the OEB's policy with respect to conditions when the deemed LT debt rate issued by the OEB would actual as a proxy or ceiling for the rate to be applied for rate-setting purposes. This includes when debt is issued by an affiliated company.

Question(s):

a) Please confirm or correct the entries in the table shown above.

EEDO Response:

Confirmed

b) Please confirm whether EPCOR Electricity Distribution Ontario will follow the OEB's policy to use the deemed LT debt rate as the ceiling on the rates of these two (2022 and 2023) debt instruments, as documented in EB-2009-0084 *Report*

[1] Ontario Energy Board, 2023 Cost of Capital Parameters, October 20, 2022

of the Board on the Cost of Capital for Ontario's Regulated Utilities, issued December 11, 2009 and as quoted in 5-Staff-56.

EEDO Response:

EEDO cannot follow the use of the deemed LT debt rate as the ceiling on the rates for the 2022 and 2023 debt instruments.

c) If the answer to part b) is no, please explain why EPCOR Electricity Distribution Ontario believes that the rate treatment for the forecasted 2022 and 2023 debt should not comply with the OEB's policy.

EEDO Response:

As noted in EEDO's response to 5-Staff-56, EEDO has discussed in detail the procedures it follows to help ensure that the ultimate actual debt rates used for EEDO are comparable to market-based rates on arms-length commercial terms.

EEDO also reiterates that it is not reasonable to have LT debt rates capped at a ceiling based on calculations prepared using data from September 2022, when actual debt issuances will not occur until well after September 2022 for both the 2022 and 2023 debt issuances.

EEDO has to issue debt based on the market conditions when the debt is actually taken out by EEDO. The components of LT debt rates, including underlying interest rates and Utility Bond Yield Spreads (or credit spreads) fluctuate constantly and the actual LT debt rates which EEDO will enter into will be based on the market conditions when EEDO places the LT debt. The market conditions may result in parameters above or below the data used in the OEB's October 20, 2022 Cost of Capital Parameters.

A clear example of this is the Government of Canada 30-year underlying rates. For the time period of October 3, 2022 to October 31, 2022 (i.e. the time since the OEB's data were collected up to September 30, 2022), the Government of Canada 30-year underlying rates ranged from 3.103% to 3.693% (based on ending Government of Canada 30-year rates for each day in this period). If EEDO had issued LT debt in this period, the underlying component of that debt could have been well in excess of the 3.231% Long Canada Bond Forecast in the OEB's calculation which would set the ceiling for affiliated debt to EEDO. This would result if EEDO not being able to recover this prudently incurred cost, not only for the upcoming cost of service period, but for the entire life of the LT debt issued. EEDO believes this would be an unfair result.

EEDO believes that the procedures to determine EEDO's LT debt rates are based on a market-based approach which would result in a market-based interest rate for the debt being issued by the utility.

6-Staff-102
Ref: 6-Staff-57

The 2021 tax return was provided. Please update the PILs Workform to reflect the 2021 tax return as well as any updates to the 2022 and 2023 forecasts.

EEDO Response:

EPCOR – The PILS Workform submitted as part of the initial IRs reflected the results of the 2021 tax return. EEDO plans on submitting an updated PILs Workform to reflect the outcomes of the settlement conference subsequent to the conference.

6-Staff-103
Ref: 6-Staff-60
PILs Workform

In response to 6-Staff-60, EPCOR Electricity Distribution Ontario noted that the reductions to UCC represents its election to deduct contributions from taxable income and reduce the tax base of the asset class instead, as well as adjustments for vehicle burden.

a) Please confirm that the election allows contributions to be deducted against the tax basis of the asset, which will reduce taxable income and that the contribution is not a direct reduction to taxable income. If not confirmed please explain.

EEDO Response:

This is correct, Subsection 13(7.4) of the *Income Tax Act* (ITA) allows a taxpayer to make an election whereby the capital cost of a depreciable property is reduced by the amount of assistance that would otherwise be included in the taxpayer's income by virtue of paragraph 12(1)(x) of the ITA.

b) In the PILs Workform, contributions and vehicle burden adjustments in column 5 reduced the UCC in Schedule 8 for the bridge and test years. In Schedule 1 of the bridge and test years, there are deductions of $172,924 and $204,069, respectively for the amortization of contributions from customers and $224,206 and $263,729, respectively for vehicle burden adjustments. Please explain whether there is any double counting of deductions relating to contributions and vehicle burden adjustments.

i. If no, please explain why not.

ii. Please revise the PILs Workform as necessary.

EEDO Response:

No, there is no double counting of deductions.

i. The amortization of contributions is deducted because the contributions are amortized into income over the useful life of the underlying asset they were paid to fund. This is deducted for tax purposes as the full value of the contribution has reduced the tax basis on the CCA schedule 8 in the year the asset is put into service. Similarly vehicle burden amortization is deducted to the extent it relates to capital projects and reduces the tax basis on the CCA schedule 8.

ii. N/A based on response to i.

9-Staff-104
Ref: 9-Staff-87
9-SEC-47
Exhibit 9/Schedule 1/Tab 1/p.24
IRR Chapter 2 Appendix 2-BA

In response to 9-SEC-47, it states that EPCOR Electricity Distribution Ontario pays CIS costs based on number of active accounts. The agreement between EPCOR Electricity Distribution Ontario and Town of Collingwood is based on number of bills adjusted annually by inflation.

In Exhibit 9 referenced above, it states

> …approximately $200k of fixed billing & collecting costs were excluded from distribution revenue requirement through revenue offsets for billing services provided by outside vendors for activities such as meter reading, bill preparation and bill fulfillment. The remaining portion of these non-electricity billing costs relate to employee time for providing billing services to the third party and EEDO is not seeking to include these costs in this deferral account.

a) Please confirm that EPCOR Electricity Distribution Ontario has included the CIS costs in Account 4380 – Expenses of Non-Rate Regulated Activities as shown in Appendix 2-H and the revenues from the Town of Collingwood in Account 4375 – Revenues of Non-Rate Regulated Activities as shown in Appendix 2-H.

EEDO Response:

Confirmed

b) If not confirmed, please explain where the costs and revenues have been reflected in the application.

EEDO Response:

N/A based on above response

c) In Appendix 2-H, the summary table shows the balance in expenses in Account 4380 to be ($775,000) and revenues in Account 4375 to be $890,000, for net revenues of $115,000. In the breakdown of the Account 4380/4375 table below, municipal service expense is greater than revenues by $115,000. Please clarify what the appropriate revenue and expense amounts are.

EEDO Response:

Water/WasteWater Billing	650,000
Water/WasteWater Service Charge	20,000
Water/WasteWater Interest	45,000
Affiliate Recoveries	175,000
4375 - 2023 Total	**890,000**

Water/Wastewater Labour	(350,000)
Water/Wastewater System Fixed	(200,000)
Water/Wastewater System Variable	(50,000)
Affiliate Expenses	(175,000)
4380 - 2023 Total	**(775,000)**

d) Please confirm that the $200,000 represents the portion of the cost paid to external vendors that is recorded in Account 4380, and the remaining portion in Account 4380 are employee costs for providing billing services.

EEDO Response:

Please refer to 9-Staff-47-c above.

i. If not confirmed, please explain what the remaining portion in Account 4380 relates to.

EEDO Response:

Please refer to 9-Staff-47-c above.

ii. If part d is not confirmed, please explain whether the employee costs are currently included in the test year OM&A. If not, please confirm that EPCOR Electricity Distribution Ontario plans to forego recovery of the employee costs for providing those billing services if the agreement with the Town of Collingwood is terminated.

EEDO Response:

Employee costs are not currently included in test year OM&A. EEDO plans to forego recovery of the employee costs for providing those billing services if the agreement with the Town of Collingwood is terminated.

e) Please confirm that $200,000 is the amount that is forecasted to be recorded in the account.

EEDO Response:

Confirmed.

SEC Pre-Settlement Conference Clarification Questions

1. [2-SEC-15d] Please provide a copy of the referenced internal audit.

EEDO Response:

The internal audit report is confidential and contains proprietary information. For this reason, EPCOR will not be filing this document as part of the public record.

2. [2-Staff-33, DSP Risk Ranking Matrix_20220825] The Project Ranking Details identifies 25 projects, with any remaining projects listed as 'future projects':

   a. Please confirm that the matrix only contains System Renewal and System Service projects.

EEDO Response:

Confirmed

   b. How are General Plant and System Access projects taken into consideration in prioritizing projects?

EEDO Response:

General Plant items such as vehicles are ranked based on age, mileage, type of use, engine hours, etc. A condition assessment referenced within the DSP is used to prioritize vehicle replacements. Other items such as communication equipment, computer hardware and software and other equipment utilize an IT/OT priority matrix referenced within the DSP to rank these projects.

System Access projects are not deemed as discretionary so are not prioritized following the methods described within the DSP.

   c. Please explain how the 25 projects were chosen, as some have lower risk scores than those considered 'future' projects.

EEDO Response:

Answer: Some of these projects with higher scores have been completed or are currently underway.

184 8th St is completed due to equipment failure.

233 St Paul St and Elm St are currently underway as they were actually already scheduled to be completed and due to safety concerns with the live front transformers.

Mill St-Louisa St to George St was pushed out as Clearview Twp. is looking at a beautification project on Mill St in Creemore, didn't want to waste funds and do things twice.

Collins-Katherine to Sproule has mostly been re-built due to Bell Fibe to Home project. The remainder will be captured in our Miscellaneous pole replacement program.

Caroline St E&W is to be dome in conjunction with Mill St-Louisa St to George St as these two projects will intersect each other.

44KV Optimization-EPCOR already has one of these automated switches that was installed in conjunction with a project that was required to extend one of our 44KV circuits to feed a new complex. It was felt that this would help lower the Reliability Risk enough that this could be completed in future years.

3. [2-Staff-18, Appendix 2-AA] The following table appears to show that the forecasted costs of replacing a pole have significantly increased in the test year:

    a. Please confirm the numbers shown in the table are correct, and if not, please provide a revised version of the table.

EEDO Response:

Confirmed

	2018	2019	2020	2021	2022	2023	Source
Pole line rebuild	$ 624,202	$ 1,941,992	$ 1,285,638	$ 1,513,561	$ 1,204,953	$ 1,276,043	Appendix 2AA
Pole replacement program	$ 370,665	$ 196,641	$ 587,011	$ 595,826	$ 558,491	$ 582,540	Appendix 2AA
Total	$ 994,867	$ 2,138,633	$ 1,872,649	$ 2,109,387	$ 1,763,444	$ 1,858,583	
Number of poles replaced	108	130	134	162	135	78	2-Staff-18
$/pole	$ 9,212	$ 16,451	$ 13,975	$ 13,021	$ 13,063	$ 23,828	
5 year average $/pole					$ 13,144		

    b. Please explain why the cost to replace a pole in 2023 is significantly higher than in previous years.

EEDO Response:

Many of the poles in our 2023 plan are rear lot construction. This is driving our labour costs higher due to the extra person hours it will take to access back yards, climb poles to complete work and complete restoration of homeowners properties compared to being able to access with bucket trucks. We will being seeing higher contractor costs associated with these projects as well due to extra equipment and time that will be required to install port-a-holes and anchors as well as crane rentals for setting poles.

4. [EEDO_2023 Load Forecast_20220825] The Summary Tables show data for 2021 as an estimate. Please update test year forecast with 2021 actuals and based on actual data to end of September 2022, update 2022 forecast as required.

EEDO Response:

Please refer to attachment 3-SEC-4 Updated Load Forecast.

5. [4-SEC-34] With respect to 4-SEC-34:

   a. With respect to the first bullet, for each year between 2019 and 2022, please provide the net cost/savings related to the difference between EEDO forecast and actuals.

EEDO Response:

Please see the table below for the net cost increase attributable to the first bullet point. One clarifying point to add to the explanation in the first bullet point is that the EPCOR Forecast assumed attrition in former the VP Operations position when the employee retired in 2021, instead the Hydro Manager position was removed when the incumbent moved into the VP Operations position when the former VP Operations retired.

	2019	2020	2021	2022
Total	74,539	108,559	147,927	229,816

   b. With respect to the second bullet point, please provide the total amount EEDO spent/forecast to spend on, i) IT/GIS OM&A, ii) finance and regulatory OM&A work, for each year between 2017 and 2023, regardless of how the work was procured (i.e. internal, external, affiliate, corporate etc.).

EEDO Response:

Please see the table below for EEDO spending on

	2017	2018	2019	2020	2021	2022	2023
IT/GIS	222,175	235,440	419,121	395,117	425,528	463,293	512,112
Finance and Regulatory	444,728	554,347	611,989	619,090	607,988	652,652	684,337

With respect to the third bullet point:

i. Please provide the corporate service costs in each year between 2019 and 2023, broken down by, “additional corporate services provided” and “higher allocation percentages as contemplated in the original forecast". Please explain how this breakdown was undertaken.

ii. Please explain what additional corporate services were provided.

EEDO Response:

i. Please see the table below for the 2019 to 2023 difference between forecasted and actual corporate service costs broken out between additional corporate services and higher allocation percentages.

The breakdown was determined by taking the actual additional allocations related to corporate services which were not contemplated in the original forecast and then subtracting this amount from the difference between the actual corporate shared services and the originally forecasted corporate shared services.

Additional costs	2019	2020	2021	2022	2023
Higher allocation percentages	206,617	130,218	195,032	214,279	287,800
Additional corporate services	16,935	25,067	28,615	32,693	32,790
Difference in corporate shared services	223,012	155,285	223,646	246,973	320,590

ii. The following additional corporate services were provided,

a. Learning and Development/Technical Training

b. Organizational Project Management

c. With respect to the fourth bullet, for each year between 2018 and 2023, please provide a breakdown of the listed items.

EEDO Response:

Please see the table below for a breakdown of the yearly difference between actual and forecast for the listed items.

	2018	2019	2020	2021	2022	2023

HSE	-	28,240	31,827	27,790	40,704	39,607
Regulatory	-	11,475	12,533	-	29,179	39,715
Operational support	-	-	57,709	58,186	67,632	67,012
Total	**-**	**39,715**	**102,069**	**85,976**	**137,515**	**146,334**

6. [4-Staff-51] Please provide a copy of the Service Level Agreements that govern recovery of costs for shared and corporate services.

EEDO Response:

Please refer to the .zip file 4-SEC-6 accompanying this submission.

7. Does the EEDO provide services to any its affiliates? If so, please provide details and the amount recovered (or forecast to be recovered) for each year between 2019 and 2023, and how the amounts are reflected in the application.

EEDO Response:

Yes, from 2019 to 2023 services were provided from EEDO to its affiliates ENGLP, EOUI/EOOMI, and EUI. The services include IT, GIS, Regulatory, Engineering and HR support as broken out in the table below.

	2019 Actual	2020 Actual	2021 Actual	2022 Forecast	2023 Test Year
IT	79,076	98,549	88,116	52,977	21,604
GIS/Engineering	5,153	15,129	7,430	7,578	7,730
Regulatory	0	42,218	83,416	85,084	86,786
HR	54,062	-	-	-	-
Total	**138,291**	**155,896**	**178,962**	**145,639**	**116,120**

The cost and FTE relating to the employee time spent providing services to affiliates has not been included in OM&A costs in the application; only the cost and time being spent on EEDO utility work is reflected in the application. The decrease in IT services being provided relates to the IT position being moved from EEDO to the EOOMI affiliate part way through 2022.

8. [4-Staff-49e] Please provide a revised version of Appendix 2-K that includes FTEs and compensation allocated from shared and corporate services.

EEDO Response:

EEDO has provided a revised Appendix 2-K below which includes FTE and compensation allocated from affiliate shared services (EOOMI/EWSI/EDTI), however is not a virtual utility as the majority of our functions are not outsourced. Note that compensation and FTE from corporate shared services is excluded (EUI) from the figures as the proportion of compensation and FTE is not determinable.

Appendix 2-K
Employee Costs

	Last Rebasing Year (2013 OEB Approved)	Last Rebasing Year (2013 Actuals)	2014 Actuals	2015 Actuals	2016 Actuals	2017 Actuals	2018 Actuals	2019 Actuals	2020 Actuals	2021 Actuals	2022 Bridge Year	2023 Test Year
Number of Employees (FTEs including Part-Time)[1]												
Management (including executive)	2.75	3.75	4.06	4.43	4.74	5.33	5.48	6.63	6.78	5.45	5.46	5.01
Non-Management (union and non-union)	20.17	18.60	18.91	19.39	20.66	22.14	23.25	23.27	25.17	25.30	26.62	26.46
Total	22.92	22.35	22.97	23.82	25.40	27.47	28.73	29.90	31.94	30.75	32.08	31.47
Total Salary and Wages including ovetime and incentive pay												
Management (including executive)	$ 429,991	$ 617,409	$ 643,069	$ 657,198	$ 812,126	$ 738,532	$ 771,857	$ 942,357	$ 979,514	$ 798,653	$ 867,673	$ 850,023
Non-Management (union and non-union)	$ 1,605,613	$ 1,474,242	$ 1,653,959	$ 1,790,226	$ 1,977,502	$ 1,940,020	$ 2,093,401	$ 2,177,392	$ 2,418,154	$ 2,479,961	$ 2,655,591	$ 2,744,111
Total	$ 2,035,604	$ 2,091,651	$ 2,297,028	$ 2,447,424	$ 2,789,628	$ 2,678,552	$ 2,865,258	$ 3,119,748	$ 3,397,667	$ 3,278,614	$ 3,523,264	$ 3,594,134
Total Benefits (Current + Accrued)												
Management (including executive)	$ 90,208	$ 173,129	$ 159,572	$ 160,914	$ 194,431	$ 187,623	$ 214,014	$ 231,478	$ 254,770	$ 214,081	$ 227,452	$ 223,853
Non-Management (union and non-union)	$ 333,867	$ 413,395	$ 410,415	$ 438,335	$ 473,433	$ 492,861	$ 580,441	$ 517,712	$ 616,037	$ 662,612	$ 680,904	$ 707,863
Total	$ 424,075	$ 586,524	$ 569,987	$ 599,249	$ 667,864	$ 680,484	$ 794,455	$ 749,190	$ 870,807	$ 876,693	$ 908,355	$ 931,716
Total Compensation (Salary, Wages, & Benefits)												
Management (including executive)	$ 520,199	$ 790,538	$ 802,640	$ 818,112	$ 1,006,557	$ 926,155	$ 985,871	$ 1,173,834	$ 1,234,284	$ 1,012,733	$ 1,095,125	$ 1,073,876
Non-Management (union and non-union)	$ 1,939,480	$ 1,887,637	$ 2,064,374	$ 2,228,561	$ 2,450,935	$ 2,432,881	$ 2,673,842	$ 2,695,104	$ 3,034,191	$ 3,142,573	$ 3,336,495	$ 3,451,974
Total	$ 2,459,679	$ 2,678,175	$ 2,867,014	$ 3,046,672	$ 3,457,492	$ 3,359,037	$ 3,659,714	$ 3,868,938	$ 4,268,475	$ 4,155,307	$ 4,431,619	$ 4,525,851
Total Compensation Breakdown (Capital, OM&A)												
OM&A	$ 2,253,759	$ 2,318,751	$ 2,532,800	$ 2,240,868	$ 2,608,256	$ 2,141,106	$ 2,527,368	$ 2,765,880	$ 3,284,270	$ 2,748,175	$ 3,098,802	$ 3,147,184
Capital	$ 205,920	$ 359,424	$ 334,214	$ 805,804	$ 849,236	$ 1,217,931	$ 1,132,345	$ 1,103,058	$ 984,205	$ 1,407,132	$ 1,332,817	$ 1,378,667
Total	$ 2,459,679	$ 2,678,175	$ 2,867,014	$ 3,046,672	$ 3,457,492	$ 3,359,037	$ 3,659,714	$ 3,868,938	$ 4,268,475	$ 4,155,307	$ 4,431,619	$ 4,525,851

EPCOR ELECRICITY DISTRIBUTION ONTARIO INC. (EEDO)
2023 RATE APPLICATION (EB-2022-0028)
PRE-SETTLEMENT FOLLOW-UP AND CLARIFICATION QUESTIONS

(Numbering follows from VECC IR numbering)

VECC-56

REFERENCE: VECC 38 c)
Exhibit 8, Tab1, Schedule 1, page 14
IRR Chapter 2 Appendices, Appendix 2-H

a) The response to VECC 38 c) states that the pole attachment charge used for forecasting Account 4210 2023 revenues was $34.76 – the approved 2022 charge. However, the Application states in Exhibit 8 that for pole rental revenue:
""In its' "Other Operating Revenue" projections for the Test Year 2021 discussed in Exhibit 6, EEDO has applied a 2% inflation rate above the Bridge Year (2021) in the absence of an OEB rate being available at the time of preparing this application". Please reconcile.

EEDO Response:

The $34.76 was included in Exhibit 8 as a placeholder on the list of customer service charges in the absence of the actual rate. EEDO will be charging third party attachments at the rate approved by the Board.

After review of the supporting information used to calculate the charge for the purposes of 2023 Operating Revenue, a rate of $34.76 was used.

b) Please explain the increase in Account 4210 revenues from $143,707 in 2022 to $219,181 in 2023.

EEDO Response:

Exhibit 6 Tab 1, Schedule 1, Page 14:

Pole Rental (4082) - An increase due to the disposition of related Pole Attachment Revenue Incremental Revenue Group 2 deferral account. As this account is closed, EEDO will charge pole attachment fees based on the Board's generic annual decision and rate order.

c) Please explain the increase in Account 4082 revenues as between 2022 and 2023.

EEDO Response:

Exhibit 6 Tab 1, Schedule 1, Page 14:

Retail Service Charges (4082) - An increase due to the disposition of related Retail Service Charge Incremental Revenue Group 2 deferral account. As this account is closed, EEDO will charge retail transactions based on the Board's annual decision and rate order.

VECC-57

REFERENCE: VECC 41

a) The response states:
"Regarding changes to the underground assumptions (1840), based on discussions with the operations team, there is a higher allocation of primary than secondary as the same type of conduit is used for both services. Primary conductor is more expensive than secondary which offset the ratio used for conduit."
The first sentence suggests that the percentage of conduit allocated to primary is higher than in the previous COS. However, the chart shows allocation to primary of 40% versus 50% in the previous COS. Please reconcile.

EEDO Response:

The response provided in VECC-41 was in response to the differences in allocation between conduit and conductor. The change from the 2013 filing for underground conduit is based on operations as there is more secondary conduit than primary. The change in ratio from conduit to conductor accounts for the "Primary conductor is more expensive than secondary which offset the ratio used for conduit" comment which increases the allocation for primary.

EB-2022-0028

EPCOR ELECTRICITY DISTRIBUTION ONTARIO INC.

SETTLEMENT PROPOSAL

Appendix E – Revised Low Voltage Rates Calculation

EB-2022-0028 Low Voltage Rate Calculation - Settlement Update

Rate Class	Unit	RTSR - Connection per kWh	RTSR - Connection per kW	Loss Adjusted Billed RTSR kWh	Billed RTSR kW	Basis for Allocation	Allocation %	Allocated $ Amount	Billed RTSR kWh	Billed RTSR kW	Calculated LV Rate/kWh	Calculated LV Rate/kW
Residential	$/kWh	*0.0051*		*145,896,967*	-	*744,075*	48.52%	$ 567,482	137,612,684	-	**0.0041**	
General Service < 50 kW	$/kWh	*0.0042*		*47,547,411*	-	*199,699*	13.02%	$ 152,304	44,847,586	-	**0.0034**	
General Service > 50 kW	$/kW		*1.7986*		*324,247*	*583,191*	38.03%	$ 444,781		324,247		**1.3717**
Unmetered Scattered Load	$/kWh	*0.0042*		*420,086*	-	*1,764*	0.12%	$ 1,346	396,233	-	**0.0034**	
Street Lighting	$/kW		*1.3904*		*3,496*	*4,861*	0.32%	$ 3,707		3,496		**1.0604**
Total						***1,533,590***	**100.00%**	**$ 1,169,621**				

2022 Projected Low Voltage Costs (2022 rates using 2021 volumes)

Primary Metering Entity	Rate Name	Rate $	2021 kW	Total
Creemore	Shared LV DS	$1.6888	2,080	$42,157
Wasaga	Shared LV DS	$1.6888	726	$14,718
Thornbury	Common ST Lines	$1.6208	4,216	$82,000
Stayner	Common ST Lines	$1.6208	49,592	$964,545
9 Wholesale Points	*Fixed Charge*	*$612.97*	*9*	*$66,201*
Total				**$1,169,621**

EB-2022-0028

EPCOR ELECTRICITY DISTRIBUTION ONTARIO INC.

SETTLEMENT PROPOSAL

Appendix F – Updated Group 2 DVA Balances

Group 2 Accounts Requested for DIsposition (Excluding 1568)

Accounts Included in Settlement Proposal

	A Account	B Name	C Dec 31, 2022 Balance	D Carrying Charges	E Total	F Dispoition Proposal
1	1508	Deferred IFRS Transition Costs	$189,206	$34,124	$223,330	$223,330
2	1508	Pole Attachment Revenue Variance	($492,217)	($27,256)	($519,473)	($519,473)
3	1508	Retail Service Charge Incremental Revenue	($29,083)	($1,480)	($30,564)	($30,564)
4	1508	Customer Choice Initiative Costs	$8,500	$431	$8,931	$0
5	1508	Other Regulatory Assets - Icon F&G Meter Disposal	$512,493	$27,050	$539,543	$539,543
6	1508	Other Regulatory Assets - Energy East Consultation Costs	$2,275	$305	$2,580	$0
7	1508	Other Regulatory Assets - LPP Variance	($2,217)	($64)	($2,282)	$0
8	1508	Foregone Revenues from Postponing Rate Implementation	($17,475)	($598)	($18,073)	($18,073)
9	1509	COVID-19 Deferral Account	$21,732	$951	$22,683	$0
10	1525	Misc. Deferred Debits	$8,105	$235	$8,340	$0
11	1592	PILs and Tax Variance for 2006 and Subsequent Years	$35,000	$4,649	$39,649	$39,649
12	1531	REG Capital Deferral Account	$1,269	$262	$1,530	$1,530
13	1532	REG Capital OM&A Account	$43,444	$3,299	$46,742	$46,742
14	1534	Smart Grid Capital Deferral Account	$4,500	$735	$5,235	$5,235
15	1555	Smart Grid Capital Deferral - Stranded Meters	$3,650	$6,633	$10,283	$10,283
16	1557	Meter Cost Deferral Account (MIST Meters)	$250,901	$21,706	$272,606	$272,606
		Total	**540,082**	**70,982**	**611,064**	**570,811**

Account Excluded in Settlement Proposal

	A Account	B Name	C Dec 31, 2022 Balance	D Carrying Charges	E Total	F Dispoition Proposal
1	1508	Other Regulatory Assets - OEB Cost Assessment Variance	$235,952	$18,385	$254,337	$254,337