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

DECISION AND ORDER

EB-2023-0033

INNPOWER CORPORATION

Application for electricity distribution rates and other charges beginning January 1, 2024

BEFORE: Allison Duff
Presiding Commissioner

Fred Cass
Commissioner

November 23, 2023

TABLE OF CONTENTS

1 OVERVIEW

This is a Decision and Order of the Ontario Energy Board (OEB) on an application filed by InnPower Corporation (InnPower) seeking approval for changes to the rates InnPower charges for electricity distribution effective January 1, 2024.

InnPower filed a settlement proposal, dated October 13, 2023, that reflected a comprehensive settlement between InnPower, Hydro One Networks Inc. (HONI), School Energy Coalition (SEC), and Vulnerable Energy Consumers Coalition (VECC) (collectively, the Parties) on all issues included on the approved Issues List.[1] A revised settlement proposal was filed November 6, 2023.

The OEB accepts the revised settlement proposal as filed. The OEB concludes that implementation of the revised settlement proposal should result in reasonable outcomes for both InnPower and its customers.

[1] The Issues List approved in the OEB's Decision on Issues List dated July 11, 2023.

2 PROCESS

The OEB's *Renewed Regulatory Framework for Electricity*[2] and *Handbook for Utility Rate Applications*[3] provide distributors with performance-based rate application options that support the cost-effective planning and efficient operation of a distribution network. This framework provides an appropriate alignment between a sustainable, financially viable electricity sector and the expectations of customers for reliable service at a reasonable price.

On May 12, 2023, InnPower filed a cost of service application with the OEB under section 78 of the *Ontario Energy Board Act, 1998* (OEB Act). The application requested OEB approval of InnPower's proposed electricity distribution rates for five years, using the Price Cap Incentive Rate-setting (Price Cap IR) option described in the *Renewed Regulatory Framework for Electricity*. Under the Price Cap IR option, with an approved 2024 Test Year, InnPower would be eligible to apply to have its 2025-2028 rates adjusted mechanistically, based on inflation and the OEB's assessment of InnPower's efficiency.

The application was accepted by the OEB as complete on May 26, 2023. The OEB issued a Notice of Hearing on June 1, 2023, inviting parties to apply for intervenor status. SEC and VECC applied for and were granted intervenor status and cost award eligibility. HONI was granted intervenor status.

The OEB did not receive any letters of comment about this proceeding.

The OEB issued Procedural Order No. 1 on June 23, 2023. This order established, among other things, the timetable for a written interrogatory discovery process and a settlement conference.

OEB staff filed a Proposed Issues List that had been agreed to by the Parties for the OEB's consideration on June 28, 2023. The OEB approved the proposed Issues List on July 11, 2023. InnPower responded to the interrogatories and follow-up questions submitted by HONI, SEC, VECC, and OEB staff.

A settlement conference was held from August 21-23, 2023. InnPower, HONI, SEC, and VECC participated in the settlement conference.

---

[2] Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach, October 18, 2012
[3] Handbook for Utility Rate Applications, October 13, 2016

InnPower filed a settlement proposal covering all issues on October 13, 2023. OEB staff filed a submission on the settlement proposal on October 24, 2023. In response to submissions made by OEB staff, InnPower filed a revised settlement proposal with certain corrections. The revised settlement proposal is attached as Schedule A to this Decision and Order.

3 DECISION ON THE SETTLEMENT PROPOSAL

The revised settlement proposal addresses all 21 issues on the OEB approved Issues List for this proceeding and represents the Parties' full settlement on each of these issues. The revised settlement proposal contains detailed explanations and rationales on these issues for the OEB to consider.

Issue 6.2 related to InnPower's request to use a deferral account to track the capital contributions made for the Barrie Area Transformer Upgrade project between 2025-2027.

Barrie Area Transmission Upgrade (BATU) Installment Deferral Account

The BATU project involves transmission line and station work to increase capacity in the Barrie/Innisfil area. HONI received approval for the BATU project through a leave to construct application in 2020 (BATU LTC decision)[4]. As part of the BATU LTC decision, HONI was also approved to recover capital contribution amounts from InnPower over a 5-year period (2023 to 2027)[5]. The specific ratemaking implications for InnPower were not part of the BATU LTC decision.

In this application, InnPower requested a deferral account to recover the revenue requirement impact of the capital contribution to HONI that would not be recovered in base rates. InnPower had considered the Advanced Capital Module (ACM) as an alternative recovery method but found that it would result in an under recovery of approximately 78%. The Parties agreed in the revised settlement proposal that the BATU deferral account should recover 50% of the revenue requirement for the capital contributions made for the BATU project that is included in base rates.

OEB staff submitted that it is reasonable for InnPower to recover amounts related to the capital contribution to HONI for the BATU. OEB staff supported the revised deferral account in the settlement proposal as it allows InnPower to recover more than it would have received under ACM treatment, while at the same point protecting ratepayers in the event the BATU project is delayed or costs change.

[4] EB-2018-0117, Decision and Order, April 23, 2020
[5] ibid, pp. 14-16.

Findings

The OEB accepts the revised settlement proposal as filed.

In the exercise of its statutory authority to fix or approve just and reasonable rates under section 78 of the OEB Act, and in the context of the statutory objectives set out in section 1 of the OEB Act, the OEB has concluded that implementation of the revised settlement proposal should result in reasonable outcomes for both InnPower and its customers. The OEB also finds that the revised settlement proposal is consistent with the Renewed Regulatory Framework and the Handbook for Utility Rate Applications.

In particular, the OEB notes the following provisions of the revised settlement proposal:

- 2024 OM&A budget was reduced by $0.75M to $7.5M, which the OEB finds reasonable given the potential economies of scale as InnPower continues to see customer growth;
- 2024 capital in-service additions were reduced by $0.4M to $10.08M, which the OEB finds reasonable given that InnPower underspent historical planned total net capital expenditures between 2017 and 2021;
- The revised settlement proposal would result in a 2.3% bill increase in 2024 for a typical residential customer with a monthly consumption of 750 kWh which the OEB finds reasonable. The final bill calculations have yet to be made with the 2024 cost of capital parameters and Regulated Price Plan electricity rates included;
- The OEB finds the BATU Installment Deferral Account appropriate given it balances the interests of shareholder(s) and customers.

Regarding the BATU Installment Deferral Account, the OEB considered the BATU LTC decision in which a 5-year capital contribution installment period was accepted in the expectation that it would save ratepayers $2 million compared to the ratepayer cost of one payment made after the asset was in service. The OEB finds the revised settlement proposal is consistent with the intent of the BATU LTC decision and Parties adequately considered alternative ratemaking options.

The OEB finds the BATU Installment Deferral Account balances the interests of shareholder(s) and customers, leading to just and reasonable rates. It is balanced because it moderates the bill impacts for customers and provides partial financial relief for InnPower's shareholder(s) during the IRM term. It is fair because it provides

InnPower's shareholder(s) with more financial relief than the ACM option and protects customers should the BATU project be delayed or project costs change.

The draft accounting order for the BATU Installment Deferral Account, previously included at Appendix G to the revised settlement proposal, is approved and attached as Schedule B to this Decision. As this new deferral account is unique, the OEB appreciates the details provided in the draft accounting order, including the three sub-accounts, proposed accounting entries, and the forecast annual disposition amounts from 2024 to 2029.

The OEB notes the following commitments made by InnPower in the revised settlement proposal:

- InnPower will file an updated draft rate order and supporting models for approval once the 2024 cost of capital parameter updates and 2024 Regulated Price Plan electricity rates have been released;
- InnPower will use reasonable efforts to file a line loss study in this proceeding by January 1, 2024;
- InnPower will investigate and use reasonable efforts to implement cost-effective, technically feasible, reliable and safe measures to reduce line losses and report back at its next rebasing application;
- InnPower may apply for disposition of balances in the BATU Installment Deferral Account on an interim basis at each IRM proceeding until its next rebasing;
- InnPower will provide a detailed accounting true-up of all BATU installment payments to allow for a full reconciliation when applying for final disposition of the account at its next rebasing.

4 IMPLEMENTATION

The OEB finds that the January 1, 2024, effective and implementation date for InnPower's updated 2024 rates is appropriate.

A draft Tariff of Rates and Charges was included with the revised settlement proposal for rates effective on January 1, 2024.

Consistent with the revised settlement proposal, InnPower shall update its short-term debt and return-on-equity[6] with the OEB's 2024 Cost of Capital Parameters, issued on October 31, 2023.[7] InnPower shall also update its Cost of Power and the associated Tariff Schedule and Bill Impacts model to reflect the Regulated Price Plan Price Report for November 1, 2023, to October 31, 2024, issued on October 19, 2023.[8]

InnPower shall file its draft rate order, updating the placeholder values for the components noted above, with detailed supporting material showing the impact of any required adjustments and corrections to the settlement proposal and DVA continuity schedule.

SEC and VECC are eligible to apply for cost awards in this proceeding. The OEB has made provision in this Decision and Order for SEC and VECC to file their cost claims.

[6] Settlement Proposal, p. 25
[7] 2024 Cost of Capital Parameters, October 31, 2023
[8] RPP Price Report - November 1, 2023 to October 31, 2024 (oeb.ca)

5 ORDER

THE ONTARIO ENERGY BOARD ORDERS THAT:

1. The Revised Settlement Proposal in Schedule A is approved.

2. InnPower Corporation shall file with the OEB and forward to intervenors a draft rate order with a proposed Tariff of Rates and Charges no later than **December 4, 2023**. InnPower Corporation shall also include customer rate impacts and detailed information in support of the calculation of final rates in the draft rate order.

3. The Accounting Order set out in Schedule B of this Decision and Order is approved.

4. HONI, SEC, VECC, and OEB staff may file any comments on the draft rate order with the OEB no later than **December 8, 2023**.

5. InnPower Corporation may file with the OEB and forward to intervenors, responses to any comments on its draft rate order no later than **December 15, 2023**.

6. SEC and VECC shall each submit its cost claim to the OEB and forward a copy to InnPower Corporation by **December 8, 2023**. SEC and VECC may include a claim of up to one hour to review and (if necessary) comment the draft rate order.

7. InnPower Corporation shall file with the OEB and forward to SEC and VECC any objections to the claimed costs by **December 15, 2023**.

8. If InnPower Corporation files an objection to the claimed costs, SEC and VECC shall file with the OEB and forward to InnPower Corporation any responses to the objection by **January 10, 2024**.

9. InnPower Corporation shall pay the OEB's costs incidental to this proceeding upon receipt of the OEB's invoice.

Parties are responsible for ensuring that any documents they file with the OEB, such as applicant and intervenor evidence, interrogatories and responses to interrogatories or any other type of document, **do not include personal information** (as that phrase is defined in the *Freedom of Information and Protection of Privacy Act*), unless filed in accordance with rule 9A of the OEB's Rules of Practice and Procedure.

Please quote file number, **EB-2023-0033** for all materials filed and submit them in searchable/unrestricted PDF format with a digital signature through the OEB's online filing portal.

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

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

With respect to distribution lists for all electronic correspondence and materials related to this proceeding, parties must include the Case Manager, Donald Lau at Donald.Lau@oeb.ca and OEB Counsel, Lawren Murray at Lawren.Murray@oeb.ca.

DATED at Toronto **November 23, 2023**

ONTARIO ENERGY BOARD

Nancy Marconi

Digitally signed by Nancy Marconi
Date: 2023.11.23 14:42:20 -05'00'

Nancy Marconi
Registrar

SCHEDULE A

DECISION AND ORDER

REVISED SETTLEMENT PROPOSAL

INNPOWER CORPORATION

EB-2023-0033

NOVEMBER 23, 2023

John Vellone
T: 416-367-6730
jvellone@blg.com

Colm Boyle
T: 416-367-7273
cboyle@blg.com

Borden Ladner Gervais LLP
Bay Adelaide Centre, East Tower
22 Adelaide Street West
Toronto ON M5H 4E3
Canada
T 416-367-6000
F 416-367-6749
blg.com

Borden Ladner Gervais

File No. 014898.000017

November 6, 2023

DELIVERED BY EMAIL & RESS

Ms. Nancy Marconi, Registrar
Ontario Energy Board
PO Box 2319
26th Floor, 2300 Yonge Street
Toronto, ON M4P 1E4

Dear Ms. Marconi:

Re: InnPower Corporation ("InnPower")
Application for 2024 Electricity Distribution Rates
Ontario Energy Board ("OEB") File No. EB-2023-0033 ("Proceeding")

We write on behalf of our client, InnPower, in response to OEB Staff's submission filed on October 24, 2023 on the Settlement Proposal filed on October 13, 2023. OEB Staff requested certain corrections to the Settlement Proposal on pages 8 and 12 in the submission. With the agreement of all Interveners, InnPower is filing the enclosed Revised Settlement Proposal to incorporate those requested changes.

If you have any questions or concerns, please do not hesitate to contact me.

Yours truly,

BORDEN LADNER GERVAIS LLP

Colm Boyle

EB-2023-0033

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 InnPower Corporation for an order approving just and reasonable rates and other charges for electricity distribution beginning January 1, 2024.

INNPOWER CORPORATION

REVISED SETTLEMENT PROPOSAL

NOVEMBER 6, 2023

InnPower Corporation
EB-2023-0033
Settlement Proposal

Table of Contents

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:

- IPC 2024_Benchmarking_Model_20231002
- IPC 2024_Cost_Allocation_Model_1.0_20231002
- IPC 2024_Demand_Data_20231002
- IPC 2024_DVA_Continuity_Schedule_CoS_1.0_20231002
- IPC 2024_Exhibit_3_LOAD_FORECAST_20231002
- IPC 2024_Filing_Requirements_Chapter2_Appendices_1.0_20231002
- IPC 2024_Rev_Reqt_Workform_1.0_20231002
- IPC 2024_RTSR_Workform_1.0_20231002
- IPC 2024_Tariff_Schedule_and_Bill_Impact_Model_20231002
- IPC 2024_Test_year_Income_Tax_PILS_1.0_20231002
- IPC 1592_CCA_Changes_Final_Settlement
- IPC Settlement_BATU_RR_and_DVA_Entries_20231011

InnPower Corporation
("InnPower")
EB-2023-0033
Settlement Proposal

Filed with OEB: November 6, 2023

SUMMARY

In reaching this complete settlement, the Parties (as defined below) have been guided by the Filing Requirements for 2024 rates, the approved issues list attached as Schedule A to the Ontario Energy Board's (the "OEB") Decision on Issues List of July 11, 2023 ("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").

Capitalized terms used in this summary but not otherwise defined herein have the meaning ascribed to such terms elsewhere in this Settlement Proposal.

This Settlement Proposal reflects a complete settlement of the issues in this proceeding. Table A is a summary of the settlement on the issues in the Approved Issues List.

Table A – Issues List Summary

Issue		Status	Supporting Parties	Parties taking no position
1.1	Capital and In-Service Additions	Complete Settlement	SEC, VECC	HONI
1.2	Rate Base and Depreciation	Complete Settlement	SEC, VECC	HONI
2.1	OM&A	Complete Settlement	SEC, VECC	HONI
2.2	Shared Services Cost Allocation Methodology	Complete Settlement	SEC, VECC	HONI
3.1	Cost of Capital and Capital Structure	Complete Settlement	SEC, VECC	HONI
3.2	PILs	Complete Settlement	SEC, VECC	HONI
3.3	Other Revenue	Complete Settlement	SEC, VECC	HONI
3.4	Impacts of Accounting Changes	Complete Settlement	SEC, VECC	HONI
3.5	Revenue Requirement Determination	Complete Settlement	SEC, VECC	HONI
4.1	Load Forecast	Complete Settlement	SEC, VECC	HONI
5.1	Cost Allocation	Complete Settlement	SEC, VECC	HONI
5.2	Rate Design, including fixed/variable splits	Complete Settlement	SEC, VECC	HONI

5.3	Retail Transmission Service Rates and Low Voltage Service Rates	Complete Settlement	SEC, VECC	HONI
5.4	Loss Factor	Complete Settlement	SEC, VECC	HONI
5.5	Specific Service Charges, Retail Service Charges	Complete Settlement	SEC, VECC	HONI
5.6	Rate Mitigation	Complete Settlement	SEC, VECC	HONI
5.7	New Embedded Distributor Rate Class	Complete Settlement	All	None
6.1	Deferral and Variance Accounts	Complete Settlement	SEC, VECC	HONI
6.2	BATU Deferral Account	Complete Settlement	SEC, VECC	HONI
7.1	Effective Date	Complete Settlement	SEC, VECC	HONI
7.2	Responding to all Relevant OEB Directions from Previous Proceedings	Complete Settlement	SEC, VECC	HONI

As a result of this Settlement Proposal, InnPower has made changes to the Revenue Requirement as depicted below in Table B.

Table B: Revenue Requirement Summary

Category	Item	Original Application	Interrogatory Response	Change	Settlement Proposal	Change	OEB Rate Update	Change	Total Change
Cost of Capital	Regulated Return on Rate Base	$4,621,661	$4,632,131	$10,470	$4,467,886	($164,245)	$4,473,906	$6,020	**($147,755)**
	Regulated Rate of Return	6.02%	6.04%	0.02%	5.98%	(0.06%)	5.98%	0.00%	**(0.04%)**
Rate Base and CAPEX	2024 Net Capital Additions	$9,120,000	$9,120,000	$ -	$10,085,730	$965,730	$10,085,730	$ -	**$965,730**
	2024 Average Net Fixed Assets	$73,777,771	$73,620,622	($157,149)	$71,715,190	($1,905,432)	$71,715,190	$ -	**($2,062,581)**
	Cost of Power	$31,662,671	$32,313,654	$650,983	$32,414,344	$100,690	$33,756,783	$1,342,439	**$2,094,112**
	Working Capital	$40,119,469	$40,770,452	$650,983	$40,121,142	($649,310)	$41,463,581	$1,342,439	**$1,344,112**
	Working Capital Allowance Rate	7.50%	7.50%	0.00%	7.50%	0.00%	7.50%	0.00%	**0.00%**
	Working Capital Allowance	$3,008,960	$3,057,784	$48,824	$3,009,086	($48,698)	$3,109,769	$1,006,83	**$100,809**
	Rate Base	$76,786,731	$76,678,406	($108,325)	$74,724,276	($1,954,130)	$74,824,959	$100,683	**($1,961,772)**
Operating Expenses	Amortization Expense	$5,027,633	$5,029,700	$2,067	$5,096,877	$67,177	$5,096,877	$ -	**$69,244**
	Grossed-up PILS	$253,241	$221,062	($32,179)	$182,950	($38,112)	$184,309	$1,359	**($68,932)**
	OM&A	$8,327,618	$8,327,618	$ -	$7,577,618	($750,000)	$7,577,618	$-	**($750,000)**
	Property Taxes	$129,180	$129,180	$ -	$129,180	$ -	$129,180	$ -	**$-**
Revenue Requirement	Service Revenue Requirement	$18,359,333	$18,339,691	($19,642)	$17,454,511	($885,180)	$17,461,890	$7,379	**($897,443)**
	Less: Other Revenues	$3,937,483	$3,417,532	($519,951)	$3,579,818	$162,286	$3,567,620	($12,198)	**($369,863)**
	Base Revenue Requirement	$14,421,850	$14,922,159	$500,309	$13,874,693	($1,047,466)	$13,894,270	$19,577	**($527,580)**
	Revenue Deficiency / (Sufficiency)	**$307,694**	**$395,462**	**$87,768**	**($709,802)**	**($1,105,264)**	**($690,225)**	**$19,577**	**($997,919)**

The Bill Impacts as a result of this Settlement Proposal is summarized in Table C. This Settlement Proposal will, if accepted, result in a total bill increase of $3.20 per month for the typical residential customer consuming 750 kWh per month.

Table C: Summary of Bill Impacts

Settlement:

RATE CLASSES / CATEGORIES *(eg: Residential TOU, Residential Retailer)*	Units	Sub-Total A $	Sub-Total A %	Sub-Total B $	Sub-Total B %	Sub-Total C $	Sub-Total C %	Total Bill $	Total Bill %
RESIDENTIAL SERVICE CLASSIFICATION - RPP	kwh	$ -	0.0%	$ (0.78)	-1.4%	$ 3.08	4.7%	$ 3.20	2.3%
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION - RPP	kwh	$ (2.65)	-3.9%	$ (4.71)	-4.4%	$ 4.70	3.5%	$ 4.98	1.5%
GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION - Non-RPP (Other)	kw	$ 47.51	6.6%	$ (58.40)	-4.5%	$ 147.41	7.9%	$ 227.50	4.3%
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION - RPP	kwh	$ (2.43)	-15.2%	$ (2.17)	-12.6%	$ (1.85)	-10.2%	$ (1.87)	-7.3%
SENTINEL LIGHTING SERVICE CLASSIFICATION - Non-RPP (Other)	kw	$ (29.09)	-34.7%	$ (27.33)	-31.1%	$ (25.72)	-27.9%	$ (26.04)	-23.7%
STREET LIGHTING SERVICE CLASSIFICATION - Non-RPP (Other)	kw	$ (8,595.46)	-36.1%	$ (8,841.50)	-35.8%	$ (8,606.05)	-33.9%	$ (9,563.07)	-25.8%
RESIDENTIAL SERVICE CLASSIFICATION - Non-RPP (Retailer)	kwh	$ -	0.0%	$ (1.40)	-2.5%	$ 2.47	3.7%	$ 2.58	1.7%
EMBEDDED DISTRIBUTOR - Non-RPP (Other)	kw	$ (55.75)	-4.7%	$ (273.53)	-11.6%	$ 79.79	2.3%	$ 296.29	2.1%

The impact of the Settlement Proposal with regards to capital expenditures and OM&A expenses results in an estimated efficiency assessment of 12.3% below predicted costs using the PEG forecasting model provided by the OEB as can be seen in Table D.

Table D: Summary of Cost Benchmarking Results

Year	Status	Total Cost	% Difference from Predicted	3-Year Average Performance	Efficiency Assessement
2021	Actuals	$ 15,145,732	-2.2%		3
2022	Actuals	$ 16,842,121	-6.8%		3
2023 Bridge Year	Forecast	$ 19,602,023	-7.8%	-5.6%	3
2024 Test Year	Forecast	$ 20,082,877	-12.3%	-9.0%	2

This Settlement Proposal also incorporates the Regulated Price Plan pricing from the OEB's Regulated Price Plan Price Report for November 1, 2022 to October 31, 2023 (Released October 20, 2022). This Settlement Proposal also incorporates the updated Cost of Capital Parameters which were issued by the Ontario Energy Board on October 20, 2022. The Revenue Requirement in Table B incorporates all of the settled issues including the RPP and Cost of Capital Updates. For information purposes only, the following tables E and F illustrate the revenue requirement on initial application and upon settlement respectively.

Table E: Revenue Requirement Summary (Initial Application/Interrogatory updates)

Line No.	Particulars	Application		Interrogatory Responses		Per Board Decision	
1	OM&A Expenses	$8,327,618		$8,327,618		$7,577,618	
2	Amortization/Depreciation	$5,027,633		$5,029,700		$5,096,877	
3	Property Taxes	$129,180		$129,180		$129,180	
5	Income Taxes (Grossed up)	$253,241		$221,062		$184,309	
6	Other Expenses	$ -					
7	Return						
	Deemed Interest Expense	$1,746,766		$1,761,292		$1,672,460	
	Return on Deemed Equity	$2,874,895		$2,870,840		$2,801,446	
8	**Requirement (before Revenues)**	$18,359,333		$18,339,691		$17,461,890	
9	Revenue Offsets	$3,937,483		$3,417,532		$3,567,620	
10	**Base Revenue Requirement (excluding Tranformer Overship Allowance credit**	$14,421,850		$14,922,159		$13,894,270	
11	Distribution revenue	$14,421,850		$14,922,159		$13,894,270	
12	Other revenue	$3,937,483		$3,417,532		$3,567,620	
13	**Total revenue**	$18,359,333		$18,339,691		$17,461,890	
14	**Less Distribution Revenue Requirement before Revenues)**	($0)	(1)	($0)	(1)	($0)	(1)

This Settlement Proposal is the culmination of extensive discussion and consideration by the Parties which represent an array of interests affected by InnPower's Application for electricity distribution rates. Based on the foregoing, and the evidence and rationale provided below, the Parties agree that this Settlement Proposal is appropriate and recommend its acceptance by the OEB. Refer to Appendix E for the Proposed Tariff of Rates and Charges resulting if this Settlement Proposal is accepted by the OEB.

Finally, the Parties accept that InnPower is compliant with the OEB's required outcomes as defined by the RRFE.

BACKGROUND

InnPower filed a Cost of Service application with the OEB on May 12, 2023 under section 78 of the *Ontario Energy Board Act*, *1998*, S.O. 1998, c. 15, (Schedule B) (the "Act"), seeking approval for changes to the rates that InnPower charges for electricity distribution, to be effective January 1, 2024 (OEB Docket Number EB-2023-0033) (the "Application").

The OEB issued and published a Notice of Hearing dated June 1, 2023, and Procedural Order No. 1 on June 23, 2023, the latter of which required the parties to the proceeding to develop a proposed issues list.

On June 28, 2023, pursuant to Procedural Order No. 1, OEB Staff submitted a proposed issues list as agreed to by the parties. OEB Staff also advised the OEB that "parties may wish to raise additional matters for inclusion on the Issues List after the responses to the interrogatories are received." On July 11, 2023, the OEB issued its Decision on Issues List, approving the list submitted by OEB Staff. This Settlement Proposal is filed with the OEB in connection with the Application and is organized in accordance with the Approved Issues List

Procedural Order No. 1 scheduled the Settlement Conference for August 21 to 23, 2023. InnPower filed most of its Interrogatory Responses with the OEB on August 8, 2023 and requested an extension until August 10, 2023 to file the remainder of the Interrogatory Responses.[1] The OEB granted the extension request on August 9, 2023. InnPower filed the remainder of its Interrogatory Responses on August 10, 2023, pursuant to which InnPower updated several models and submitted them to the OEB as Excel documents.

A Settlement Conference was convened between August 21 to 23, 2023 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 acted as facilitator for the Settlement Conference which lasted for three days.

InnPower and the following Intervenors (the "Intervenors"), participated in the Settlement Conference:

Hydro One Networks Inc. ("HONI")
School Energy Coalition ("SEC"); and
Vulnerable Energy Consumers Coalition ("VECC").

InnPower and the Intervenors are collectively referred to below as the "Parties".

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

[1] The outstanding responses included 1-Staff-1, 4-Staff-56, 8-Staff-64 and 8-VECC-32.

This document is called a “Settlement Proposal” because it is a proposal by the Parties to the OEB to settle the issues in this proceeding. It is termed a proposal as between the Parties and the OEB. However, as between the Parties, and subject only to the OEB’s approval of this Settlement Proposal, this document is intended to be a legal agreement, creating mutual obligations, and binding and enforceable in accordance with its terms. As set forth later in this Preamble, this agreement 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 Agreement, 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 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 Agreement, 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 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.

This Settlement Proposal provides a brief description of each of the settled and partially settled issues, as applicable, together with references to the evidence. The Parties agree that references to the “evidence” in this Settlement Proposal shall, unless the context otherwise requires, include (a) additional information included by the Parties in this Settlement Proposal; (b) the Appendices to this document; and (c) the evidence filed concurrently with this Settlement Proposal titled “Responses to Pre-Settlement Clarification Questions” (“Clarification Responses”). The supporting Parties for each settled issue, as applicable, agree that the evidence in respect of that settled or partially settled issue, as applicable, 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 InnPower. While the Intervenors have reviewed the Appendices, the Intervenors are relying on the accuracy of those Appendices and the underlying evidence in entering into this Settlement Proposal.

Outlined below are the final positions of the Parties following the Settlement Conference. For ease of reference, this Settlement Proposal follows the format of the final Approved Issues List for the Application attached to the Decision on Issues List dated July 11, 2023.

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

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

According to the Practice Direction (p. 2), the Parties must consider whether a Settlement Proposal should include an appropriate adjustment mechanism for any settled issue that may be affected by external factors. These adjustments are specifically set out in the text of the Settlement Proposal.

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

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

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

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

1. Capital Spending and Rate Base

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

Complete Settlement: Subject to the adjustments expressly noted in this Settlement Proposal, the Parties accept that the 2023 in-service additions, 2024 capital expenditures and 2024 in-service additions, set out in Clarification Response SEC-1, are appropriate.

InnPower applied for $11.96 million in 2023 net CAPEX. As part of the response to Interrogatory 2-Staff-4, InnPower updated the Chapter 2 Appendices, including Appendix 2-AA, to account for updates to the work schedule since the application was filed. While the overall 2023 net CAPEX remained at $11.96 million, revisions were made to estimated costs for allocation of capital between individual projects. As part of Clarification Response SEC-1, InnPower made further revisions to the forecasts of in-service additions and work in progress for certain projects (IPCSS11 – InnPower TS Pre-Works and IPCSS18 – 44kV Line Extension from Barrie) to reflect updates to the work schedule. Again, the 2023 net CAPEX remained at $11.96 million following Clarification Response SEC-1.

InnPower applied for $9.12 million in 2024 net in-service additions. As part of Clarification Responses SEC-1 and 6-Staff-82, the 2024 net in-service additions were updated to $10.49 million to account for changes in InnPower's work schedule and depreciation, which included the addition of the Enterprise Resource Planning Software ($160,000) to project "IPCGP05 - FINANCE IT", new wholesale meters ($185,000) to project "IPCSA05 - METERING", and a new project "IPCSS18 - 44kV Line Extension from Barrie" ($1,020,730) in Appendix 2-AA.

Also, as part of Clarification Response SEC-1, InnPower revised its 2024 capital expenditure forecast, the details of which are appended to the Clarification Responses.

For the purposes of settlement, the Parties agree to the following adjustments:

1. InnPower will reduce its capital expenditures and in-service additions in the 2024 Test Year by $400,000. The total net capital expenditures in the 2024 Test Year shall be $17.86 million, as further detailed in Table 1.1A. The total net in-service additions in the 2024 Test Year shall be $10.09 million, as further detailed in Table 1.1B.

Table 1.1A
Summary of Capital Expenditures

2023 Bridge Year

	Original Application	Interrogatory Response	Change	Pre-Settlement	Change	Settlement Proposal	Change	Total Change
System Access	$25,414,636	23,956,893	($1,457,743)	23,956,893	$0	23,956,893	$0	**($1,457,743)**
System Renewal	$9,994,041	$11,686,276	$1,692,235	$11,686,276	$0	$11,686,276	$0	**$1,692,235**
System Service	$11,966,515	$11,511,264	($455,251)	$11,511,264	$0	$11,511,264	$0	**($455,251)**
General Plant	$1,630,669	$1,851,429	$220,760	$1,851,429	$0	$1,851,429	$0	**$220,760**
Total CAPEX	$49,005,861	$49,005,862	$1	$49,005,862	$0	$49,005,862	$0	**$1**
Capital Contributions	($37,045,575)	($37,045,576)	$1	($37,045,576)	$0	($37,045,576)	$0	**$1**
Net CAPEX	$11,960,286	$11,960,286	$0	$11,960,286	$0	$11,960,286	$0	**$0**

2024 Test Year

Investment Category	Application	Interrogatory Response	Change	Clarfication Responses	Change	Settlement Proposal	Change	Total Change
System Access	$23,410,348	$23,410,348	$0	$30,750,036	7,339,688	$30,350,036	($400,000)	**6,939,688**
System Renewal	$1,429,409	$1,429,409	$0	$7,257,607	5,828,198	$7,257,607	$0	**5,828,198**
System Service	$7,518,600	$7,518,600	$0	$16,313,227	8,794,627	$16,313,227	$0	**8,794,627**
General Plant	$1,021,991	$1,021,991	$0	$1.181,991	160,000	$1,181,991	$0	**160,000**
Total CAPEX	$33,380,348	$33,380,349	$0	$55,502,861	22,122,513	$55,102,861	$0	**21,722,512**

Capital Contributions	($24,260,349)	($24,260,349)	$0	($37,243,235)	12,982,886	($37,243,235)	$0	**12,982,886**
Net CAPEX	$9,120,000	$9,120,000	$0	$18,259,627	9,139,627	$17,859,627	($400,000)	**8,739,627**

Table 1.1B
2023 Bridge Year In-Service Additions

	Original Application	Interrogatory Response	Change	Settlement Proposal	Change	Total Change
Net In-Service Additions	$11,960,286	11,960,286	$0	$9,589,398	($2,370,888)	**($2,370,888)**

2024 Test Year In-Service Additions

	Original Application	Interrogatory Response	Change	Settlement Proposal	Change	Total Change
Net In-Service Additions	$9,120,000	10,485,730	$1,365,730	$10,085,730	($400,000)	**$965,730**

Evidence:

Application:

- Exhibit 1
  - 1.1.5.1.1 Application Summary (Introduction)
  - 1.1.5.1.6 Key Work Activities in 2024
  - 1.1.5.2.3 Rate Base and Distribution Plan
- Exhibit 2, Appendix 2-5-3 (DSP)
- Exhibit 2
  - 2.1.1 Rate Base Overview
  - 2.1.2 Rate Base Variance Analysis
  - 2.2.1 Property, Plant and Equipment
  - 2.3.1 Depreciation
  - 2.4.1 Allowance for Working Capital
  - 2.5.1 Capital Expenditures and In-Service Additions Summary
  - 2.5.2 Capital Expenditure Variance Analysis
  - 2.5.3 Distribution System Plan

IRRs:

- 2-Staff-2, 2-Staff-3, 2-Staff-4, 2-Staff-5, 2-Staff-6, 2-Staff-7, 2-Staff-8, 2-Staff-9, 2-Staff-10, 2-Staff-11, 2-Staff-12, 2-Staff-13, 2-Staff-14, 2-Staff-15, 2-Staff-16, 2-Staff-17, 2-Staff-18, 2-Staff-19, 2-Staff-20, 2-Staff-21, 2-Staff-22, 2-Staff-23, 2-Staff-24, 2-Staff-25, 2-Staff-26, 2-Staff-28, 2-Staff-29, 2-Staff-30, 2-Staff-31, 2-Staff-32, 2-Staff-33, 2-Staff-34, 2-Staff-35, 2-Staff-36, 2-Staff-37, 2-Staff-38, 2-Staff-39, 1-SEC-5, 1-SEC-14, 2-SEC-15, 2-SEC-16, 2-SEC-17, 2-SEC-18, 2-SEC-19, 2-SEC-20, 2-SEC-21, 2-SEC-22, 2-SEC-23, 2-SEC-24, 2-SEC-25, 2-SEC-26, 2-SEC-27, 2.0-VECC-4, 2.0-VECC-5, 2.0-VECC-6, 2.0-VECC-7

Appendices to this Settlement Proposal:

- Appendix B – Updated Appendix 2-AB Capital Expenditure Summary

- Appendix C – Updated Appendix 2-BA Fixed Asset Continuity Schedule

- Appendix D – Bill Impacts to this Settlement Proposal

Settlement Models:

- IPC_2024_Filing_Requirements_Chapter2_Appendices_20230907

Clarification Responses:

- 2-Staff-74, 2-Staff-75, 2-Staff-76, 2-Staff-77, 2-Staff-78, SEC-1, SEC-2, SEC-3, SEC-4, SEC-5

Supporting Parties: SEC, VECC.

Parties Taking No Position: HONI.

1.2 Are the proposed rate base and depreciation amounts appropriate?

Complete Settlement: The Parties accept that the updated rate base and depreciation amounts, adjusted to reflect various aspects of the settlement, are appropriate.

The Parties agree that the working capital calculations have been appropriately determined in accordance with OEB policies and practices. InnPower utilizes the OEB's default allowance for working capital, which is set at 7.5% of the sum of the Cost of Power and OM&A under section 2.2.5 of the OEB's Chapter 2 Filing Requirements for 2024 Rate Applications, as shown in Table 1.2B below.

Table 1.2A
Depreciation

	Original Application	Interrogatory Response	Change	Settlement Proposal	Change	Total Change
Depreciation	$ 5,027,633	$5,029,700	$ 2,067	$ 5,096,877	$67,177	**$69,244**

Table 1.2B
Rate Base

Category	Item	Original Application	Interrogatory Response	Change	Settlement Proposal	Change	OEB Rate Update	Change	Total Change
Average Net Fixed Assets	Opening Cost	$ 91,707,063	$ 91,707,063	$ -	$ 89,336,175	($ 2,370,888)	$89,336,175	$ -	**($ 2,370,888)**
	Closing Cost	$100,761,612	$ 100,761,611	$ -	$ 99,356,454	($ 1,405,157)	$99,356,454	$ -	**($ 1,405,157)**
	Average Cost	$ 96,234,337	$ 96,234,337	$ -	$ 94,346,314	($ 1,888,023)	$94,346,314	$ -	**($ 1,888,023)**
	Opening Accumulated Depreciation	($21,014,265)	($21,170,381)	($ 156,116)	($21,235,344)	($ 64,963)	$21,235,344	$ -	**($ 221,079)**
	Closing Accumulated Depreciation	($23,898,867)	($24,057,049)	($ 158,182)	($24,026,904)	($ 30,145)	$24,026,904	$ -	**($ 128,037)**
	Average Depreciation	($22,456,566)	($22,613,715)	($ 157,149)	($22,631,124)	($ 17,409)	$22,631,124	$ -	**($ 174,558)**
	Average Net Fixed Assets	**$ 73,777,771**	**$ 73,620,622**	**($ 157,149)**	**$ 71,715,190**	**($ 1,905,432)**	**$71,715,190**	**$ -**	**($ 2,062,581)**
Working Capital Allowance	OM&A	$ 8,327,618	$ 8,327,618	$ -	$ 7,577,618	($ 750,000)	$7,577,618	$ -	**($ 750,000)**
	Property Tax	$ 129,180	$ 129,180	$ -	$ 129,180	$ -	$129,180	$ -	**$ -**
	Cost of Power	$ 31,662,671	$ 32,313,654	$ 650,983	$ 32,414,344	$ 100,690	$33,756,783	$1,342,439	**$ 2,094,112**
	Total Working Capital	$ 40,119,469	$ 40,770,452	$ 650,983	$ 40,121,142	($ 649,310)	$41,463,581	$1,342,439	**$1,344,112**
	Working Capital Allowance Rate	7.50%	7.50%	$ -	7.50%	$ -	7.50%	$ -	**$ -**
	Working Capital Allowance	$ 3,008,960	$ 3,057,784	$ 48,824	$ 3,009,086	($ 48,698)	$3,109,769	$100,683	**$100,809**
Rate Base	**Rate Base**	**$ 76,786,731**	**$ 76,678,406**	**($ 108,325)**	**$ 74,724,276**	**($ 1,954,130)**	**$74,824,959**	**$100,683**	**($ 1,961,772)**

Evidence:

Application:

- Exhibit 1
  - 2.3 Rate Base and Distribution System Plan
- Exhibit 2
  - 2.1.1 Rate Base Overview
  - 2.1.2 Rate Base Variance Analysis
  - 2.2.1.2 Gross Assets – Property, Plant and Equipment and Accumulated Depreciation
  - 2.3.1 Depreciation and Amortization
  - 2.5.4.1.3 Amortization/Depreciation (Capitalization Policy)

IRRs:

- 6-Staff-62, 2-Staff-38

Appendices to this Settlement Proposal: N/A

Settlement Models:

- IPC_2024_Filing_Requirements_Chapter2_Appendices_20230907

Clarification Responses:

- 6-Staff-82

Supporting Parties: SEC, VECC.

Parties Taking No Position: HONI.

2. OM&A

2.1 Are the proposed OM&A expenditures appropriate?

Complete Settlement: The Parties agree that InnPower will reduce its proposed OM&A expenses in the 2024 Test Year by $750,000. The revised proposed amount of $7,706,798 (including property tax) in the 2024 Test Year is appropriate.

The Parties also agree that InnPower will manage its OM&A budget as it and specific adjustments to InnPower's OM&A plans have not been finalized and may change. InnPower notes that it has applied the $750,000 reduction in the tables throughout this settlement document and the live excel models as an envelope adjustment.

As shown in Table 2.1A below, Total 2024 Settlement Test Year OM&A Expenses have increased by 26% compared to December 31, 2017, Actuals (representing an annual growth rate of approximately 3.7% per year). During that period (from 2017 actuals to 2024 forecast), InnPower will see a customer growth rate of 32.2% for Residential, GS<50 and GS>50 customers. It is expected that InnPower will move to the Group 2 productivity rating in 2024. Table 2.1B below is a Summary of OM&A expenses with variance. InnPower confirms that this level of spending is sufficient to maintain a safe and reliable distribution system.

Table 2.1A
Appendix 2-JA
Summary of OM&A Expenses

	2017 Last Rebasing Year OEB Approved	2017 Last Rebasing Year Actuals	2018 Actuals	2019 Actuals	2020 Actuals	2021 Actuals	2022 Actuals	2023 Bridge Year	2024 Test Year
Reporting Basis	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
Operations	$ 1,358,964	$ 1,600,622	$ 1,396,958	$ 1,313,975	$ 1,104,679	$ 1,548,761	$ 1,370,149	$ 1,741,822	$ 1,797,038
Maintenance	$ 574,925	$ 616,264	$ 631,423	$ 652,489	$ 762,292	$ 1,049,233	$ 948,218	$ 880,390	$ 1,015,169
SubTotal	**$ 1,933,889**	**$ 2,216,886**	**$ 2,028,381**	**$ 1,966,464**	**$ 1,866,971**	**$ 2,597,994**	**$ 2,318,367**	**$2,622,213**	**$2,812,208**
%Change (year over year)		14.6%	-8.5%	-3.1%	-5.1%	39.2%	-10.8%	13.1%	7.2%
%Change (Test Year vs Last Rebasing Year - Actual)									26.9%
Billing and Collecting	$ 1,020,051	$ 1,016,438	$ 1,085,093	$ 1,132,149	$ 1,251,092	$ 1,067,987	$ 1,475,945	$ 1,156,048	$ 1,086,995
Community Relations	$ 10,331	$ 6,406	$ 72,722	$ 48,694	$ 76,635	$ 104,431	$ 98,992	$ 109,700	$ 103,618
Administrative and General	$ 2,364,646	$ 2,773,463	$ 2,596,226	$ 2,492,553	$ 3,068,386	$ 2,687,710	$ 3,131,450	$ 3,634,981	$ 3,574,797
SubTotal	**$ 3,395,028**	**$ 3,796,307**	**$ 3,754,041**	**$ 3,673,396**	**$ 4,396,113**	**$ 3,860,128**	**$ 4,706,387**	**$4,900,729**	**$ 4,765,411**
%Change (year over year)		11.8%	-1.1%	-2.1%	19.7%	-12.2%	21.9%	4.1%	-2.8%
%Change (Test Year vs Last Rebasing Year - Actual)									25.5%
Total	**$ 5,328,917**	**$ 6,013,192**	**$ 5,782,421**	**$ 5,639,860**	**$ 6,263,084**	**$ 6,458,122**	**$ 7,024,754**	**$7,522,941**	**$7,577,618**
%Change (year over year)		12.8%	-3.8%	-2.5%	11.1%	3.1%	8.8%	7.1%	0.7%

	2017 Last Rebasing Year OEB Approved	2017 Last Rebasing Year Actuals	2018 Actuals	2019 Actuals	2020 Actuals	2021 Actuals	2022 Actuals	2023 Bridge Year	2024 Test Year
Operations[4]	$ 1,358,964	$ 1,600,622	$ 1,396,958	$ 1,313,975	$ 1,104,679	$ 1,548,761	$ 1,370,149	$ 1,741,822	$ 1,797,038
Maintenance[5]	$ 574,925	$ 616,264	$ 631,423	$ 652,489	$ 762,292	$ 1,049,233	$ 948,218	$ 880,390	$ 1,015,169
Billing and Collecting[6]	$ 1,020,051	$ 1,016,438	$ 1,085,093	$ 1,132,149	$ 1,251,092	$ 1,067,987	$ 1,475,945	$ 1,156,048	$ 1,086,995
Community Relations[7]	$ 10,331	$ 6,406	$ 72,722	$ 48,694	$ 76,635	$ 104,431	$ 98,992	$ 109,700	$ 103,618
Administrative and General[8]	$ 2,364,646	$ 2,773,463	$ 2,596,226	$ 2,492,553	$ 3,068,386	$ 2,687,710	$ 3,131,450	$ 3,634,981	$ 3,574,797
Total	**$ 5,328,917**	**$ 6,013,192**	**$ 5,782,421**	**$ 5,639,860**	**$ 6,263,084**	**$ 6,458,122**	**$ 7,024,754**	**$7,522,941**	**$7,577,618**
%Change (year over year)		12.8%		-6.2%	11.1%	3.1%	8.8%	7.1%	0.7%

Table 2.1B
Summary of OM&A Expenses with Variance

Item	Original Application	Interrogatory Response	Change	Settlement Proposal	Change	Total Change
Operations	$ 1,974,901	$ 1,974,901	$ -	$ 1,974,901	$ -	$ -
Maintenance	$ 1,115,647	$ 1,115,647	$ -	$ 1,115,655	$ -	$ -
Billing and Collecting	$ 1,194,581	$ 1,194,581	$ -	$ 1,194,581	$ -	$ -
Community Relations	$ 113,874	$ 113,874	$ -	$ 113,874	$ -	$ -
Administrative and General	$ 3,928,615	$ 3,928,615	$ -	$ 3,928,606	$ -	$ -
Settlement Reduction				**($ 750,000)**	**($ 750,000)**	**($ 750,000)**
Total OM&A Excl. Property Tax	**$ 8,327,618**	**$ 8,327,618**	**$ -**	**$ 7,577,618**	**($ 750,000)**	**($ 750,000)**
Property Tax	$ 129,180	$ 129,180	$ -	$ 129,180	$ -	$ -
Total OM&A Incl. Property Tax	**$ 8,456,798**	**$ 8,456,798**	**$ -**	**$ 7,706,798**	**($ 750,000)**	**($ 750,000)**

Evidence:

Application:

- Exhibit 1
  - 1.1.5.2.4 Operations, Maintenance and Administration (OM&A) Expense
  - 1.1.5.1.1.2 The Impact on OM&A Expenditures
  - 1.1.5.1.6 Key Work Activities
  - 1.1.11 Benchmarking
- Exhibit 4

IRRs:

- 4-Staff-42, 4-Staff-43, 4-Staff-44, 4-Staff-45, 4-Staff-46, 4-Staff-47, 4-Staff-48, 4-Staff-49, 4-Staff-50, 4-Staff-51, 4-Staff-52, 4-Staff-53, 4-Staff-54, 4-Staff-55, 4-Staff-56, 4-Staff-57, 4-Staff-58, 4-Staff-59, 4-SEC-28, 4-SEC-29, 4-SEC-30, 4-SEC-31, 4-SEC-32, 4-SEC-33, 4-SEC-34, 4-SEC-35, 4-SEC-36, 4.0-VECC-14, 4.0-VECC-15, 4.0-VECC-16, 4.0-VECC-17, 4.0-VECC-18, 4.0-VECC-19, 4.0-VECC-20, 4.0-VECC-21, 4.0-VECC-22

Appendices to this Settlement Proposal: N/A

Settlement Models:

- IPC_2024_Filing_Requirements_Chapter2_Appendices_20230907
- IPC_2024_Benchmarking_Model_20230907

Clarification Responses: 4-Staff-80, 4-Staff-81, SEC-7, VECC-48

Supporting Parties: SEC, VECC.

Parties Taking No Position: HONI.

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

Complete Settlement: The Parties agree that InnPower's proposed shared services cost allocation methodology and quantum are appropriate.

Evidence:

Application:

- Exhibit 1
  - 1.1.4.16 Corporate and Utility Organizational Structure
- Exhibit 4
  - 4.2.1 Shared Services and Corporate Cost Allocations
  - Appendix 4-2-1 (A) Elenchus Affiliate Relationship Code Review Report

IRRs:

- 4-Staff-56, 4-Staff-57, 4-SEC-33, 4-SEC-35

Appendices to this Settlement Proposal: N/A

Settlement Models:

- IPC_2024_Filing_Requirements_Chapter2_Appendices_20230907

Clarification Responses:

- 2-Staff-81, VECC-48

Supporting Parties: SEC, VECC.

Parties Taking No Position: HONI.

3. Cost of Capital, PILs, and Revenue Requirement

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

Complete Settlement: Subject to the adjustments expressly noted in this Settlement Proposal, the Parties agree that the proposed cost of capital and capital structure are appropriate. Specifically:

Cost of Capital (see Tables 3.1A and 3.1B below)*:* The Parties accept that the cost of capital calculations have been appropriately determined in accordance with OEB policies and practices. InnPower has agreed to update cost of short term debt and the return on equity capital once the OEB releases the 2024 "Cost of Capital Parameter Updates". The Draft Rate Order attached at Appendix E uses the 2023 Cost of Capital Parameters. The Parties agree that InnPower will file an updated Draft Rate Order for approval, along with the updated models, once both the 2024 "Cost of Capital Parameter Updates" and 2024 Regulated Price Plan electricity rates (see section 3.5 below) have been released.

With respect to the long-term debt ("LTD") rate, and as set out in Table 3.1A below, the Parties agree that:

a) the forecasted interest rate for all loans with a 2024 start date in Table 3.1A below will be set at 5% for the applicable period in 2024 based on the start date;
b) the interest rate for the 2023 CAPEX LOAN shall be prorated based on the start date; and
c) the principal balance for the TD-20 LOAN and TD-21 LOAN shall be prorated based on the start date since these loans are scheduled to be renewed in 2024.

Table 3.1A
Appendix 2-OB

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) [2]	Interest ($) [1]
1	TD-15 Loan	TD Canada Trust	Third-Party	Variable Rate	26-Mar-22	14	$ 2,218,160	2.70%	$ 59,890.32
2	TD-13 Loan	TD Canada Trust	Third-Party	Fixed Rate	7-Oct-22	4	$ 2,506,102	5.27%	$ 132,071.59
3	TD-03 Loan	TD Canada Trust	Third-Party	Fixed Rate	26-Nov-23	10	$ 2,088,716	5.00%	$ 104,435.81
4	TD-20 Loan	TD Canada Trust	Third-Party	Fixed Rate	23-Jul-24	10	$ 1,552,634	4.42%	$ 68,587.38
5	TD-21 Loan	TD Canada Trust	Third-Party	Fixed Rate	25-Nov-24	10	$ 1,568,095	4.02%	$ 63,050.28
6	TD-03 Loan	TD Canada Trust	Third-Party	Fixed Rate	9-Jan-15	10	$ 1,565,516	3.68%	$ 57,610.99
7	TD-26 Loan	TD Canada Trust	Third-Party	Fixed Rate	26-Dec-21	3.5	$ 9,392,408	2.88%	$ 270,501.35
8	TD-10 Loan	TD Canada Trust	Third-Party	Fixed Rate	12-Feb-16	10	$ 2,378,844	3.48%	$ 82,783.77
9	TD-22 Loan	TD Canada Trust	Third-Party	Fixed Rate	31-Jan-17	30	$ 2,573,529	3.60%	$ 92,647.04
10	TD-16 Loan	TD Canada Trust	Third-Party	Fixed Rate	26-Mar-18	30	$ 1,469,359	4.09%	$ 60,096.80
11	TD-06 Loan	TD Canada Trust	Third-Party	Fixed Rate	26-Aug-19	30	$ 2,121,541	3.28%	$ 69,586.53
12	TD-17 Loan	TD Canada Trust	Third-Party	Fixed Rate	14-Jul-21	15	$ 2,343,764	2.45%	$ 57,422.22
13	Infrastructure Ontario Loan	Infrastructure Ontario	Third-Party	Fixed Rate	15-Aug-11	15	$ 333,333	3.91%	$ 13,033.34
14	TD-01 Loan	TD Canada Trust	Third-Party	Fixed Rate	29-Oct-10	20	$ 781,584	1.92%	$ 15,006.40
15	2023 CAPEX Loan	TD Canada Trust	Third-Party	Fixed Rate	1-Apr-24	15	$ 3,970,706	5.00%	$ 198,535.31
Total							$ 36,864,291	3.65%	$ 1,345,259.12

Table 3.1B
Cost of Capital – Appendix 2-OA

Original Application

Year: **2024**

Line No.	Particulars	Capitalization Ratio (%)		Capitalization Ratio ($)	Cost Rate (%)	Return ($)
	Debt					
1	Long-term Debt	56.00%		$43,000,570	3.72%	$1,599,643
2	Short-term Debt	4.00%	(1)	$3,071,469	4.79%	$147,123
3	**Total Debt**	60.0%		$46,072,039	3.79%	$1,746,766
	Equity					
4	Common Equity	40.00%		$30,714,693	9.36%	$2,874,895
5	Preferred Shares			$ -		$ -
6	**Total Equity**	40.0%		$30,714,693	9.36%	$2,874,895
7	**Total**	100.0%		$76,786,731	6.02%	$4,621,661

IR Update

Year: **2024**

Line No.	Particulars	Capitalization Ratio (%)		Capitalization Ratio ($)	Cost Rate (%)	Return ($)
	Debt					
1	Long-term Debt	56.00%		$42,939,907	3.76%	$1,614,376
2	Short-term Debt	4.00%	(1)	$3,067,136	4.79%	$146,916
3	**Total Debt**	60.0%		$46,007,044	3.83%	$1,761,292
	Equity					
4	Common Equity	40.00%		$30,671,362	9.36%	$2,870,840
5	Preferred Shares			$ -		$ -
6	**Total Equity**	40.0%		$30,671,362	9.36%	$2,870,840
7	**Total**	100.0%		$76,678,406	6.04%	$4,632,131

Pre-Settlement Clarification

Year: **2024**

Line No.	Particulars	Capitalization Ratio (%)		Capitalization Ratio ($)	Cost Rate (%)	Return ($)
	Debt					
1	Long-term Debt	56.00%		$41,983,745	3.76%	$1,578,428
2	Short-term Debt	4.00%	(1)	$2,998,839	4.79%	$143,644
3	**Total Debt**	60.0%		$44,982,584	3.83%	$1,722,072
	Equity					
4	Common Equity	40.00%		$29,988,390	9.36%	$2,806,913
5	Preferred Shares			$ -		$ -
6	**Total Equity**	40.0%		$29,988,390	9.36%	$2,806,913
7	**Total**	100.0%		$74,970,974	6.04%	$4,528,985

Settlement Proposal

Year: 2024

Line No.	Particulars	Capitalization Ratio (%)		Capitalization Ratio ($)	Cost Rate (%)	Return ($)
	Debt					
1	Long-term Debt	56.00%		$41,845,594	3.65%	$1,527,038
2	Short-term Debt	4.00%	(1)	$2,988,971	4.79%	$143,172
3	**Total Debt**	60.0%		$44,834,565	3.73%	$1,670,210
	Equity					
4	Common Equity	40.00%		$29,889,710	9.36%	$2,797,677
5	Preferred Shares			$ -		$ -
6	**Total Equity**	40.0%		$29,889,710	9.36%	$2,797,677
7	**Total**	100.0%		$74,724,276	5.98%	$4,467,886

OEB Rate Updates

Year: 2024

Line No.	Particulars	Capitalization Ratio (%)		Capitalization Ratio ($)	Cost Rate (%)	Return ($)
	Debt					
1	Long-term Debt	56.00%		$41,901,977	3.65%	$1,529,095
2	Short-term Debt	4.00%	(1)	$2,992,998	4.79%	$143,365
3	**Total Debt**	60.0%		$44,894,975	3.73%	$1,672,460
	Equity					
4	Common Equity	40.00%		$29,929,983	9.36%	$2,801,446
5	Preferred Shares			$ -		$ -
6	**Total Equity**	40.0%		$29,929,983	9.36%	$2,801,446
7	**Total**	100.0%		$74,824,959	5.98%	$4,473,906

Evidence:

Application:

- Exhibit 1
  - 1.1.5.2.5 Cost of Capital
- Exhibit 5

IRRs:

- 5-Staff-60, 5-SEC-37, 5-SEC-38, 5.0-VECC-23, 5.0-VECC-24, 5.0-VECC-25

Appendices to this Settlement Proposal: N/A

Settlement Models:

- IPC_2024_Filing_Requirements_Chapter2_Appendices_20230907

Clarification Responses: N/A

Supporting Parties: SEC, VECC.

Parties Taking No Position: HONI.

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

Complete Settlement: The Parties agree that the proposed PILs are appropriate. A summary of the updated PILs calculation is presented in Table 3.2A below, including the updates in Clarification Response 6-Staff-82.

Table 3.2A
Grossed-Up PILs

Category	Item	Original Application	Interrogatory Response	Change	Settlement Proposal	Change	OEB Rate Change	Change	Total Change
Grossed Up PILS	Income Taxes (Not grossed up)	$ 186,132	$162,481	($ 23,651)	$ 134,468	($ 28,013)	$135,467	$999	**($ 50,665)**
	Income Taxes (Grossed up)	$ 253,241	$ 221,062	($ 32,179)	$ 182,950	($ 38,112)	$184,309	$1,359	**($ 68,932)**

Evidence:

Application:
- Exhibit 6
  - 6.2.1 Payment in Lieu of Taxes

IRRs:
- 6-Staff-61, 6-Staff-62, 8-Staff-68, 8-Staff-69, 9-Staff-70, 9.0-VECC-45

Appendices to this Settlement Proposal: N/A

Settlement Models:

- IPC_2024_Test_year_Income_Tax_PILS_1.0_20230907

Clarification Responses:

- 6-Staff-82

Supporting Parties: SEC, VECC.

Parties Taking No Position: HONI.

3.3 Is the proposed Other Revenue forecast appropriate?

Complete Settlement: The Parties accept that the other revenue forecast, as updated, is appropriate. In accordance with 4-Staff-53 and Clarification Response VECC-48, InnPower made certain corrections to Account 4375 and 4380 (-$591,951). The Parties have agreed to make adjustment to Account 4245 to reflect the increased amortized deferred revenue consistent with corrections made as part of Clarification Question SEC-1 (+162,286).

The updated forecast of total Other Revenue is $3,567,620, a decrease of $369,863 relative to the amount included in the original application, as shown in Table 3.3A below.

Table 3.3A
Other Revenue

Other Revenue	Account	Original Application	Interrogatory Response	Change	Settlement Proposal	Change	OEB Rate Change	Change	Total Change
Specific Service Charges	4235	$ 258,228	$ 258,228	$ -	$ 258,228	$ -	$258,228	$ -	$ -
Late Payment Charges	4225	$ 139,200	$ 139,200	$ -	$ 139,200	$ -	$139,200	$ -	$ -
Other Revenue	4082, 4086, 4210, 4245	$ 3,165,639	$ 2,645,688	($ 519,951)	$ 2,807,974	$ 162,286	$2,795,776	($12,198)	($369,863)
Other Income or Deductions	4355, 4375, 4380, 4390, 4405	$ 374,416	$ 374,416	$ -	$ 374,416	$ -	$374,416	$ -	$ -
Total Other Revenue		**$ 3,937,483**	**$ 3,417,532**	**($ 519,951)**	**$ 3,579,818**	**$ 162,286**	**$3,567,620**	**($12,198)**	**($ 369,863)**

Evidence:

Application:

- Exhibit 6
  - 6.3.1 Other Revenue

IRRs:

- 6-SEC-39

Appendices to this Settlement Proposal: N/A

Settlement Models:

- IPC_2024_Filing_Requirements_Chapter2_Appendices_20230907

Clarification Responses:

- VECC-48

Supporting Parties: SEC, VECC.

Parties Taking No Position: HONI.

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

Complete Settlement: For the purposes of settlement, the Parties accept that all impacts of any changes in accounting standards, policies, estimates and adjustments have been properly identified and recorded, and the rate-making treatment of each of these impacts is appropriate.

Evidence:

Application:

- Exhibit 1
  - 1.1.4.18 Accounting Standards
  - 1.1.4.19 Accounting Orders

IRRs: N/A

Appendices to this Settlement Proposal: N/A

Settlement Models: N/A

Clarification Responses: N/A

Supporting Parties: SEC, VECC.

Parties Taking No Position: HONI.

3.5 Is the proposed calculation of the Revenue Requirement appropriate?

Complete Settlement: The Parties accept that the proposed Revenue Requirement has been accurately determined based on the elements of this Settlement Proposal. A summary of the adjusted Base Revenue Requirement of $13,874,693, reflecting adjustments and settled issues, is presented in Table 3.5A below. Table 3.5B identifies the agreed upon elements for the cost of power.

InnPower has agreed to update the Cost of Power once the OEB releases the 2024 Regulated Price Plan electricity rates. The Draft Rate Order attached at Appendix E uses the 2024 Regulated Price Plan electricity rates. The Parties agree that InnPower will file an updated Draft Rate Order for approval, along with the updated models, once both the 2024 "Cost of Capital Parameter Updates" (see section 3.1 above) and 2024 Regulated Price Plan electricity rates have been released.

Table 3.5A
Revenue Sufficiency

Category	Item	Original Application	Interrogatory Response	Change	Settlement Proposal	Change	OEB Rate Change	Change	Total Change
Service Revenue Requirement	OM&A	$8,327,618	$8,327,618	$ -	$7,577,618	($ 750,000)	$7,577,618	$ -	($ 750,000)
	Property Taxes	$ 129,180	$ 129,180	$ -	$ 129,180	$ -	$129,180	$ -	$ -
	Amortization Expense	$5,027,633	$5,029,700	$ 2,067	$5,096,876	$ 67,176	$5,096,876	$ -	$ 69,243
	Regulated Return on Rate Base	$4,621,661	$4,632,131	$ 10,470	$4,467,886	($ 164,245)	$4,473,906	$6,020	($ 147,755)
	Grossed Up PILS	$ 253,241	$ 221,062	($ 32,179)	$ 182,950	($ 38,112)	$184,309	$1,359	($ 68,932)
	Service Revenue Requirement	$18,359,333	$18,339,691	($ 19,642)	$17,454,511	($ 885,180)	$17,461,890	$7,379	($ 897,443)
Revenue Offsets	Other Revenues	$ 3,937,483	$ 3,417,532	($ 519,951)	$ 3,579,818	$ 162,286	$3,567,620	($12,198)	($ 369,863)
Base Revenue Requirement	Base Revenue Requirement	$ 14,421,850	$ 14,922,159	$ 500,309	$ 13,874,693	($ 1,047,466)	$13,894,270	$19,577	($ 527,580)
Revenue Sufficiency	Distribution Revenue at Current Rates	$ 14,114,157	$ 14,526,697	$ 412,540	$ 14,584,495	$ 57,798	$14,584,495	$ -	$ 470,338
	Revenue Deficiency / (Sufficiency)	**$ 307,694**	**$ 395,462**	**$ 87,768**	**($ 709,802)**	**($ 1,105,264)**	**($ 689,225)**	**$ 20,577**	**($ 996,919)**

Table 3.5B
Cost of Power

Cost of Power	Original Application	Interrogatory Response	Change	Settlement Proposal	Change	OEB Rate Change	Change	Total Change
4705 - Power Purchased	$ 25,372,580	$ 25,839,004	$ 466,423	$ 25,928,082	$ 89,078	$25,928,082	$ -	**$ 555,502**
4707 - Global Adjustment	$ 2,749,541	$ 2,871,273	$ 121,733	$ 2,871,821	$ 548	$2,871,821	$ -	**$ 122,280**
4708 - Charges WMS	$ 1,437,010	$ 1,466,248	$ 29,238	$ 1,470,917	$ 4,669	$1,470,917	$ -	**$ 33,907**
4714 - Charges NW	$ 2,476,312	$ 2,517,725	$ 41,413	$ 2,526,095	$ 8,370	$3,161,280	$ 635,185	**$ 684,968**
4716 - Charges CN	$ 1,776,183	$ 1,805,887	$ 29,704	$ 1,811,891	$ 6,004	$2,623,720	$ 811,829	**$ 847,537**
4730 - RRRP	$ 223,535	$ 228,083	$ 4,548	$ 228,809	$ 726	$228,809	$ -	**$ 5,274**
4750 - Charges LV	$ 1,217,954	$ 1,238,568	$ 20,614	$ 1,242,624	$ 4,056	$1,252,752	$ 10,128	**$ 34,798**
4751 - IESO SME	$ 107,254	$ 110,630	$ 3,376	$ 111,134	$ 504	$111,134	$ -	**$ 3,880**
Misc A/R or A/P	($ 3,697,697)	($ 3,763,763)	($ 66,066)	($ 3,777,028)	($ 13,265)	($3,891,732)	($ 114,704)	**($ 194,035)**
Total	**$ 31,662,671**	**$ 32,313,654**	**$ 650,983**	**$ 32,414,344**	**$ 100,690**	**$33,756,783**	**$ 1,342,439**	**$ 2,094,112**

Evidence:

Application:

- Exhibit 1
  - 1.1.5.2.1 Revenue Requirement
- Exhibit 6
  - 6.1.1 Revenue Requirement and Revenue Deficiency and Sufficiency

IRRs:

- 1-Staff-1, 6.0-VECC-26

Appendices to this Settlement Proposal: N/A

Settlement Models:

- IPC_Rev_Req_Workform_1.0_20230907

- IPC_2024_Filing_Requirements_Chapter2_Appendices_20230907

Clarification Responses: N/A

Supporting Parties: SEC, VECC.

Parties Taking No Position: HONI.

4. Load Forecast

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

Complete Settlement: Subject to the adjustments expressly noted in this Settlement Proposal, the Parties accept that the customer forecast, load forecast, conservation and demand management adjustments and the resulting billing determinants are an appropriate forecast of the energy and demand requirements of InnPower's customers, consistent with OEB policies and practices.

For the purposes of settlement, the Parties agreed to the following adjustments and update the load forecast accordingly:

- The Parties accept that InnPower will increase its forecast for residential customer connections in 2024 by 100 customers to a total of 20,736, resulting in a corresponding increase of 738,527 kWh. The load forecast in Table 4.1A below has been updated accordingly.

The billing determinants are reproduced below as Table 4.1A:

Table 4.1A
Billing Determinants

Rate Class	Item	Application	Interrogatory Response	Change	Settlement Proposal	Change	Total Change
Residential	Customers	19,957	20,636	679	20,736	100	**779**
	kWh	190,211,161	195,560,391	5,349,230	196,515,750	955,359	**6,304,589**
GS<50 kW	Customers	1,324	1,314	(10)	1,314	-	**(10)**
	kWh	45,901,003	43,470,009	(2,430,994)	43,471,713	1,704	**(2,429,290)**
GS 50 to 4999 kW	Customers	80	87	7	87	-	**7**
	kW	152,108	156,827	4,719	156,832	5	**4,724**
Unmetered Scattered Load	Customers	71	75	4	75	-	**4**
	kWh	441,081	466,609	25,528	466,609	-	**25,528**
Sentinel Lighting	Customers	147	149	2	149	-	**2**
	kW	263	267	4	267	-	**4**
Street Lighting	Customers	4,334	4,460	126	4,460	-	**126**
	kW	2,623	2,674	51	2,674	-	**51**
Embedded Distributor	Customers	1	1	0	1	-	**0**
	kW	2,355	2,361	6	2,361	-	**6**

Evidence:

Application:

- Exhibit 1
  - 1.1.5.2.2 Load Forecast
- Exhibit 3

IRRS:
- 3-Staff-40, 3-Staff-41,3-SEC-26, 3-SEC-27, 3.0-VECC-8, 3.0-VECC-9, 3.0-VECC-10, 3.0-VECC-11, 3.0-VECC-12, 3.0-VECC-13

Appendices to this Settlement Proposal: **N/A**

Settlement Models:

- IPC_2024_Filing_Requirements_Chapter2_Appendices_20230907
- IPC_Exhibit_3_LOAD FORECAST_20230907

- IPC_2024_Demand_Data_20230907

Clarification Responses:
- 3-Staff-79, SEC-6, VECC-46, VECC-47

Supporting Parties: SEC, VECC.

Parties Taking No Position: HONI.

5. Cost Allocation, Rate Design, and Other Charges

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

Complete Settlement: Subject to the adjustments expressly noted in this Settlement Proposal, the Parties agree that InnPower's proposals on cost allocation methodology, allocations, and revenue-to-cost ratios are appropriate.

For the purposes of settlement, the Parties agreed to the following commitment:

- The Parties agree that InnPower will update its load profile for its next rebasing application.

The revenue-to-cost ratios are reproduced below in Table 5.1A.

Table 5.1A
Revenue to Cost Ratios

Rate Class	Revenue to Cost Ratios Resulting from Cost Allocation Model	Proposed Revenue to Cost Ratio	OEB Target Low	OEB Target High
Residential	103.15%	103.15%	85%	115%
GS<50 kW	88.14%	88.14%	80%	120%
GS 50 to 4999 kW	73.72%	81.33%	80%	120%
Sentinel Lighting	164.36%	120.00%	80%	120%
Street Lighting	164.84%	120.00%	80%	120%
Unmetered Scattered Load	132.02%	120.00%	80%	120%
Embedded Distributor	114.64%	114.63%	80%	120%

Evidence:

Application:
- Exhibit 1
  - 1.1.5.2.6 Cost Allocation and Rate Design
- Exhibit 7

IRRs:
- 7-Staff-63, 7-VECC-31

Appendices to this Settlement Proposal: N/A

Settlement Models:

- IPC_2024_Cost_Allocation_Model_1.0_20230907

Clarification Responses:

- VECC-49

Supporting Parties: SEC, VECC.

Parties Taking No Position: HONI.

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

Complete Settlement: Subject to the adjustments expressly noted in this Settlement Proposal, the Parties accept that InnPower's proposal for rate design, including fixed/variable splits, is appropriate.

For the purposes of settlement, the Parties agreed to make the following adjustments and update rate design accordingly:

For GS<50 and GS to 4999 kw rate class, the 2024 monthly service charge will remain at the approved 2023 level. The Parties agree that maintaining the fixed service charge is not meant to be precedent, and is being agreed to in the context of a full settlement and shall not bind the Parties in any future proceedings.

The fixed-variable splits and the resultant proposed fixed and variable charges are reproduced below in Tables 5.2A and 5.2B.

Table 5.2A
Fixed Variable Split

Rate Class	Allocated Base Revenue Requirement	Percentage from Fixed	Percentage from Variable	Fixed Component of Revenue Requirement	Variable Component of Revenue Requirement	Transformer Allowance
Residential	$ 11,409,280	100.00%	0.00%	$ 11,409,280	$ -	$ -
GS<50 kW	$ 1,158,504	62.94%	37.06%	$ 729,158	$ 429,346	$ -
GS 50 to 4999 kW	$ 1,050,897	23.52%	76.48%	$ 247,180	$ 803,717	$ 22,494
Sentinel Lighting	$ 29,614	59.50%	40.50%	$ 17,621	$ 11,994	$ -
Street Lighting	$ 211,971	74.33%	25.67%	$ 157,555	$ 54,416	$ -
Unmetered Scattered Load	$ 20,518	53.53%	46.47%	$ 10,983	$ 9,534	$ -
Embedded Distributor	$ 13,486	20.05%	79.95%	$ 2,704	$ 10,782	$ -
Total	**$ 13,894,270**			**$ 12,574,480**	**$ 1,319,790**	

Table 5.2B
Proposed Distribution Rates

Rate Class	Variable Billing Unit	Proposed Monthly Charge	Proposed Variable Rate
Residential	kWh	$ 45.85	$ -
GS<50 kW	kWh	$ 46.24	$ 0.0099
GS 50 to 4999 kW	kW	$ 236.52	$ 5.2681
Sentinel Lighting	kW	$ 9.85	$ 44.8815
Street Lighting	kW	$ 2.94	$ 20.3515
Unmetered Scattered Load	kWh	$ 12.13	$ 0.0204

Embedded Distributor	kW	$ 225.32	$ 4.5660

Evidence:

Application:

- Exhibit 1
  - 1.1.5.2.6.1 Cost Allocation and Rate Design
- Exhibit 8
  - 8.1.1 Rate Design

IRRs:

- 8.0-VECC-32, 8.0-VECC-33, 8.0-VECC-34, 8.0-VECC-38, 8.0-VECC-39, 8.0-VECC-40, 8.0-VECC-41, 8.0-VECC-42, 8-Staff-64, 8-Staff-65, 8-Staff-66, 8-Staff-67, 8-Staff-68, 8-Staff-69

Appendices to this Settlement Proposal:

- Appendix D – Bill Impacts to this Settlement Proposal

Settlement Models:

- IPC_2024_Cost_Allocation_Model_1.0_20230907

Clarification Responses: N/A

Supporting Parties: SEC, VECC.

Parties Taking No Position: HONI.

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

Complete Settlement: Subject to the commitment expressly noted in this Settlement Proposal, the Parties agree that the proposed Retail Transmission Service Rates and Low Voltage Rates are appropriate.

For the purposes of settlement, the Parties agreed to the following commitment:

- InnPower shall apply to the OEB prior to the next rebasing application to update its low voltage rates to reduce large balances from accumulating.

The draft rate order attached at Appendix E uses the 2024 Preliminary Uniform Transmission Rates issued on September 28, 2023, under EB-2023-0222. The Retail Transmission Service Rates and Low Voltage Rates have been reproduced below in Tables 5.3A and 5.3B.

Table 5.3A
Retail Transmission Service Rates (RTSR)

Rate Class	Billing Units	Line and Transformation Connection Service Rate	Network Service Rate
Residential	kWh	$ 0.0101	$ 0.0078
GS<50 kW	kWh	$ 0.0091	$ 0.0072
GS 50 to 4999 kW	kW	$ 3.5905	$ 4.0901
GS 50 to 4999 kW (Interval)	kW	$ 3.5905	$ 3.8324
Sentinel Lighting	kW	$ 2.8099	$ 3.1965
Street Lighting	kW	$ 2.7959	$ 2.1560
Unmetered Scattered Load	kWh	$ 0.0091	$ 0.0072
Embedded Distributor	kW	$ 3.5905	$ 3.8324

Table 5.3B
Low Voltage Rates

Rate Class	Billing Units	Low Voltage Rate
Residential	kWh	$ 0.0040
GS<50 kW	kWh	$ 0.0036
GS 50 to 4999 kW	kW	$ 2.0729
GS 50 to 4999 kW (Interval)	kW	$ 1.9424
Sentinel Lighting	kW	$ 1.6200
Street Lighting	kW	$ 1.0927
Unmetered Scattered Load	kWh	$ 0.0036
Embedded Distributor	kW	$ 1.9427

Evidence:

Application:
- Exhibit 8
  - 8.2.1 Retail Transmission Service Rates (RTSRs)

IRRs:
- HONI-1, 8.0-VECC-33, 8.0-VECC-34,

Appendices to this Settlement Proposal: N/A

Settlement Models:

- IPC_2024_RTSR_Workform_1.0_20230907

Clarification Responses: N/A

Supporting Parties: SEC, VECC.

Parties Taking No Position: HONI.

5.4 Are the proposed loss factors appropriate?

Complete Settlement: Subject to the commitments expressly noted in this Settlement Proposal, the Parties agree that the proposed loss factors are appropriate.

For the purposes of settlement, the Parties agreed to the following commitments:

- InnPower will use reasonable efforts to file the line loss study, referred to in 8-Staff-66(a), in this proceeding by January 1, 2024. The Parties agree there is currently insufficient data available for a full and accurate analysis of line losses.
- InnPower will investigate and use reasonable efforts to implement cost effective, technically feasible, reliable and safe measures to reduce line losses and report back at the next rebasing application.

The loss factor calculation is reproduced below as Table 4.1B:

Table 4.1B
Loss Factor
Appendix 2R

		Historical Years					5-Year Average
		2018	2019	2020	2021	2022	
	Losses Within Distributor's System						
A(1)	"Wholesale" kWh delivered to distributor (higher value)	285,074,581	288,210,355	299,261,031	303,807,771	307,736,609	296,818,069
A(2)	"Wholesale" kWh delivered to distributor (lower value)	278,813,236	280,581,537	291,404,252	295,240,254	299,934,504	289,194,757
B	Portion of "Wholesale" kWh delivered to distributor for its Large Use Customer(s)	-	-	-	-	-	-
C	Net "Wholesale" kWh delivered to distributor = **A(2) - B**	278,813,236	280,581,537	291,404,252	295,240,254	299,934,504	289,194,757
D	"Retail" kWh delivered by distributor	263,499,386	270,098,352	275,892,822	278,373,132	283,532,335	274,279,205
E	Portion of "Retail" kWh delivered by distributor to its Large Use Customer(s)	-	-	-	-	-	-
F	Net "Retail" kWh delivered by distributor = **D - E**	263,499,386	270,098,352	275,892,822	278,373,132	283,532,335	274,279,205
G	Loss Factor in Distributor's system = **C / F**	1.0581	1.0388	1.0562	1.0606	1.0578	1.0543
	Losses Upstream of Distributor's System						
H	Supply Facilities Loss Factor	1.0225	1.0272	1.0270	1.0290	1.0260	1.0263
	Total Losses						
I	Total Loss Factor = **G x H**	1.0819	1.0671	1.0847	1.0914	1.0854	1.0821

Evidence:

Application:
- Exhibit 8
  - 8.8.1 Loss Adjustment Factor

IRRs:
- 8-Staff-66, HONI-2

Appendices to this Settlement Proposal: N/A

Settlement Models:

- IPC_2024_Filing_Requirements_Chapter2_Appendices_20230907

Clarification Responses: N/A

Supporting Parties: SEC, VECC.

Parties Taking No Position: HONI.

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

Complete Settlement: Subject to the adjustment expressly noted in this Settlement Proposal, the Parties agree that InnPower's proposed Specific Service Charges and Retail Service Charges are appropriate as shown in the Tariff Schedule and Bill Impacts Model.

For the purposes of settlement, the Parties agreed to the following adjustment:

- InnPower shall not charge residential customers a service charge for reconnecting service after hours for an emergency disconnection. "Emergency" shall be interpreted to mean the same as it is defined under section 1.2 of the Distribution System Code. The residential customer is limited to one no-charge after hours reconnection per emergency disconnection event, and only after the emergency disconnection event has been resolved.

The draft rate order attached at Appendix E uses the 2024 Retail Service Charges issued on September 26, 2023, under EB-2023-0193.

Evidence:

Application:
- Exhibit 8
    - 8.3.1 Retail Service Charges
    - 8.5.1 Specific Service Charges

IRRs:
- 8.0-VECC-35, 8.0-VECC-36, 8.0-VECC-37, 8-VECC-38, 8-Staff-65

Appendices to this Settlement Proposal: N/A

Settlement Models: N/A

Clarification Responses: N/A

Supporting Parties: SEC, VECC.

Parties Taking No Position: HONI.

5.6 Are rate mitigation proposals required and appropriate?

Complete Settlement: The Parties agree that rate mitigation proposals are not required for any of InnPower's rate classes.

Please see Table C in the summary section above for the summary of bill impact.

Evidence:

Application:
- Exhibit 8
    - 8.12.1 Rate Mitigation

IRRs: N/A

Appendices to this Settlement Proposal:

- Appendix D – Bill Impacts to this Settlement Proposal

Settlement Models:

- IPC_2024_Tariff_Schedule_and_Bill_Impact_Model_20230907

Clarification Responses: N/A

Supporting Parties: SEC, VECC.

Parties Taking No Position: HONI.

5.7 Is the new Embedded Distributor rate class appropriate?

Complete Settlement: The parties agree that the new embedded distributor rate class is appropriate.

Evidence:

Application:
- Exhibit 1
  - 1.1.9 Host vs. Embedded Distributor

IRRs:
- 1-SEC-9, 3.0-VECC-9, 7.0-VECC-30, 7.0-VECC-31, 8.0-VECC-32, HONI-1, HONI-3, HONI-4

Appendices to this Settlement Proposal: N/A

Settlement Models:

- IPC_2024_Cost_Allocation_Model_1.0_20230907

Clarification Responses:

- VECC-49

Supporting Parties: All.

Parties Taking No Position: None.

6. Deferral and Variance Accounts

6.1 Are the 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?

Complete Settlement: Subject to the adjustments expressly noted in this Settlement Proposal, the Parties agree that InnPower'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, are appropriate. For the purposes of settlement, the Parties agreed to the following treatment of a deferral and variance account:

- InnPower shall dispose of Account 1592 up until the end of December 31, 2023, over a one-year period using the forecasted balances in 9-SEC-41 and updated for any changes that result from this Settlement Proposal.

Table 6.1A below sets out the Deferral and Variance Account balances as updated to reflect this Settlement Proposal. Principal amounts in Table 6.1A are based on disposal of Account 1592 up until the end of December 31, 2023 and all other accounts disposed up until the end of December 31, 2022. Table 6.1B below details proposed rate riders. Table 6.1C below details what Deferral and Variance Accounts will continue, discontinue or will be new as of January 1, 2024.

Table 6.1A
Deferral and Variance Account Balances and Discontinuing

Account Description	USoA	Principal	Interest to 31-Dec-22	Total	Projected Interest	Total Claim	Disposition Method
Group 1 Accounts							
LV Variance Account	1550	498,259	13,095	511,354	7,461	518,815	Rate Rider for Group 1
Smart Metering Entity Charge Variance Account	1551	(57,013)	(524)	(57,537)	(854)	(58,391)	Rate Rider for Group 1
RSVA - Wholesale Market Service Charge	1580	667,036	12,597	679,633	9,989	689,622	Rate Rider for Group 1
Variance WMS – Sub-account CBR Class B	1580	(34,560)	(977)	(35,537)	(518)	(36,055)	Rate Rider for Group 1
RSVA - Retail Transmission Network Charge	1584	1,001,491	18,278	1,019,769	14,997	1,034,766	Rate Rider for Group 1
RSVA - Retail Transmission Connection Charge	1586	585,262	11,882	597,144	8,764	605,908	Rate Rider for Group 1
RSVA - Power (excluding Global Adjustment)	1588	663,094	14,242	677,336	9,930	687,266	Rate Rider for Group 1
RSVA - Global Adjustment	1589	14,705	1,202	15,907	220	16,127	Rate Rider for Group 1

DVA Regulatory Balances (2019)	1595	(78,208)	51,726	(26,482)	0	0	
DVA Regulatory Balances (2020)	1595	(329,761)	163,969	(165,792)	(4,938)	0	
DVA Regulatory Balances (2021)	1595	(36,771)	11,924	(24,847)	(551)	0	
DVA Regulatory Balances (2022)	1595	136,543	19,963	156,506	2,045	0	
Group 1 total (including Account 1589)		**3,030,077**	**317,377**	**3,347,454**	**46,545**	**3,458,059**	
Group 1 total (excluding Account 1589)		**3,015,372**	**316,175**	**3,331,547**	**46,325**	**3,441,932**	
Account Description	**USoA**	**Principal**	**Interest to 31-Dec-22**	**Total**	**Projected Interest**	**Total Claim**	
Group 2 Accounts							
Vegetation Management	1508	(88,274)	0	(88,274)	0	(88,274)	Rate Rider for Group 2
Difference in Revenue from Affiliates	1508	(162,871)	(12,527)	(175,398)	0	0	
Difference in Expense from Affiliates	1508	95,418	7,493	102,911	0	0	
Customer Choice Initiatives	1508	4,999	129	5,128	75	0	
Green Button Initiative	1508	1,362	8	1,370	20	0	
Pole Attachment	1508	29,013	194	29,207	434	0	
Broadband Expansion	1508	1,998	24	2,022	30	0	
Retail Cost Variance Account - Retail	1518	83,180	8,687	91,867	4,091	95,958[2]	Rate Rider for Group 2
Pension & OPEB	1522	0	419	419	0	419	Rate Rider for Group 2
Retail Cost Variance Account - STR	1548	8,283	1,003	9,286	124	9,410	Rate Rider for Group 2
Subtotal		**(26,892)**	**5,430**	**(21,462)**	**4,774**	**17,513**	
PILs and Tax Variance for 2006 and Subsequent Years- CCA Changes	1592	(1,166,737)	(11,406)	(1,178,143)	(49,601)	(1,227,744)	Rate Rider for Group 2
Group 2 Total (including 1592)		**(1,193,630)**	**(5,976)**	**(1,199,605)**	**(44,827)**	**(1,210,231)**	
LRAM Variance Account	1518	0	0	0	0	0	
Smart Meter Capital and Recovery Offset Variance - Stranded Meter Costs	1555	(49,618)	(1,148)	(50,766)	(743)	(51,509)	Rate Rider for Group 2
Group 2 Total		**(1,243,247)**	**(7,124)**	**(1,250,371)**	**(45,570)**	**(1,261,740)**	
Group 1 & Group 2 Total		**1,786,830**	**310,253**	**2,097,083**	**975**	**2,196,319**	

[2] Please see IR response 9-Staff-73 for an explanation of changes that occurred since filing.

Table 6.1B
Proposed Rate Riders

Rate Rider Calculation for Group 1 Deferral / Variance Accounts Balances (excluding Global Adj.)

1550, 1551, 1584, 1586, 1595, 1580 and 1588

Rate Class (Enter Rate Classes in cells below)	Units	kW / kWh / # of Customers	Allocated Group 1 Balance (excluding 1589)	Rate Rider for Deferral/Variance Accounts
Residential	kWh	196,515,750	$ 2,245,739	**0.0114**
GS<50 kW	kWh	43,471,713	$ 505,433	**0.0116**
GS 50 to 4999 kW	**kW**	156,832	$ 698,785	**4.4556**
Unmetered Scattered Load	kWh	466,609	$ 5,463	**0.0117**
Sentinel Lighting	**kW**	267	$ 1,131	**4.2316**
Street Lighting	**kW**	2,674	$ 10,482	**3.9202**
Embedded Distributor	**kW**	2,361	$ 10,953	**4.6385**
Total			**$3,477,986**	

Rate Rider Calculation for Account 1580, sub-account CBR Class B

1580, Sub-account CBR Class B

Rate Class (Enter Rate Classes in cells below)	Units	kW / kWh / # of Customers	Allocated Sub-account 1580 CBR Class B Balance	Rate Rider for Sub-account 1580 CBR Class B
Residential	kWh	196,515,750	($ 24,243)	**(0.0001)**
GS<50 kW	kWh	43,471,713	($ 5,363)	**(0.0001)**
GS 50 to 4999 kW	**kW**	156,832	($ 6,154)	**(0.0392)**
Unmetered Scattered Load	kWh	466,609	($ 58)	**(0.0001)**
Sentinel Lighting	**kW**	267	($ 12)	**(0.0446)**
Street Lighting	**kW**	2,674	($ 110)	**(0.0413)**
Embedded Distributor	**kW**	2,361	($ 115)	**(0.0489)**
Total			**($ 36,054)**	

Rate Rider Calculation for RSVA Global Adjustment

Balance of Account 1589 Allocated to Non-WMPs

Rate Class (Enter Rate Classes in cells below)	Units	kWh	Allocated Global Adjustment Balance	Rate Rider for RSVA - Power - Global Adjustment
Residential	kWh	2,433,926	$ 860	**0.0004**
GS<50 kW	kWh	4,791,683	$ 1,693	**0.0004**
GS 50 to 4999 kW	**kWh**	37,309,435	$ 13,182	**0.0004**
Unmetered Scattered Load	kWh	38,153	$ 13	**0.0004**
Sentinel Lighting	**kWh**	96,591	$ 34	**0.0004**
Street Lighting	**kWh**	38,153	$ 13	**0.0004**
Embedded Distributor	**kWh**	935,589	$ 331	**0.0004**
Total			**$ 16,127**	

Rate Rider Calculation for Group 2 Accounts (Excluding 1518, 1548 and 1555)

Rate Class (Enter Rate Classes in cells below)	Units	kW / kWh / # of Customers	Allocated Group 2 Balance	Rate Rider for Group 2 Accounts
Residential	# of Customers	20,736	($ 855,879)	**(3.44)**
GS<50 kW	kWh	43,471,713	($ 189,331)	**(0.0044)**
GS 50 to 4999 kW	**kW**	156,832	($ 259,961)	**(1.6576)**
Unmetered Scattered Load	kWh	466,609	($ 2,032)	**(0.0044)**
Sentinel Lighting	**kW**	267	($ 421)	**(1.5743)**
Street Lighting	**kW**	2,674	($ 3,899)	**(1.4584)**
Embedded Distributor	**kW**	2,361	($ 4,075)	**(1.7256)**
Total			**($ 1,315,599)**	

Rate Rider Calculation for Group 2 Accounts (1518, 1548 and 1555 only)

Rate Class (Enter Rate Classes in cells below)	Units	kW / kWh / # of Customers	Allocated Group 2 Balance	Rate Rider for Group 2 Accounts
Residential	# of Customers	20,736	$ 33,017	$ 0.1327
GS<50 kW	# of Customers	1,314	$ 2,092	$ 0.1327
GS 50 to 4999 kW	# of Customers	87	$ 342	$ 0.3274
Unmetered Scattered Load	# of Customers	75	$ 296	$ 0.3274
Sentinel Lighting	# of Customers	149	$ 586	$ 0.3274
Street Lighting	# of Customers	4,460	$ 17,520	$ 0.3274
Embedded Distributor	# of Customers	1	$ 4	$ 0.3274
Total			**$ 53,858**	

Table 6.1C
Deferral and Variance Accounts to Continue/Discontinue/New as of January 1, 2024

Account Description	Account	Continue / Discontinue
Group 1		
LV Variance Account	1550	Continue
Smart Meter Entity Charge	1551	Continue
RSVA WMS	1580	Continue
RSVA WMS CBR Class A	1580	Continue
RSVA WMS CBR Class B	1580	Continue
RSVA Network	1584	Continue
RSVA Connection	1586	Continue
RSVA Power	1588	Continue
RSVA Global Adjustment	1589	Continue
Disposition and Recovery/Refund of Regulatory Balance (2019)	1595	Discontinue
Disposition and Recovery/Refund of Regulatory Balance (2020)	1595	Continue
Disposition and Recovery/Refund of Regulatory Balance (2021)	1595	Continue
Disposition and Recovery/Refund of Regulatory Balance (2022)	1595	New
Group 2		
Other Regulatory Assets - Sub-Account		

Vegetation Management	1508	Discontinue
Affiliate Services	1508	Discontinue
Customer Choice Initiative	1508	Discontinue
Green Button Implementation	1508	Continue
Pole Attachment	1508	Discontinue
Broadband Expansion	1508	Continue
Ultra-Low Overnight Rate Implementation	1508	Continue
COVID-19	1509	Discontinue
RCVA - Retail	1518	Discontinue
Pension & OPEB Forecast Accrual versus Actual Cash Payment Differential Carrying Charges	1522	Continue
RCVA - STR	1548	Discontinue
Stranded Smart Meters	1555	Discontinue
LRAM	1568	Continue
RSVA - One-Time	1582	Continue
PILS and Tax Variance	1592	Continue
Other Regulatory Liabilities	2405	Continue

Evidence:

Application:

- Exhibit 1
  - 1.1.5.2.7 Deferral and Variance Account
- Exhibit 9

IRRs:

- 9-SEC-40, 9-SEC-41, 9.0-VECC-43, 9-Staff-70, 9-Staff-71, 9-Staff-72, 9-Staff-73, 9.0-VECC-43, 9.0-VECC-44, 9.0-VECC-45

Appendices to this Settlement Proposal: N/A

Settlement Models:

- IPC_2024_DVA_Continuity_Schedule_CoS_1.0_20230907

Clarification Responses: N/A

Supporting Parties: SEC, VECC.

Parties Taking No Position: HONI.

6.2 Is InnPower's request to use a deferral account to track the capital contributions made for the Barrie Area Transformer Upgrade project between 2025-2027 appropriate? In the alternative, if the deferral account is not approved, is InnPower's request to use the Advanced Capital Module to recover the capital contributions made for the Barrie Area Transformer Upgrade project between 2025-2027 appropriate?

Complete Settlement: In the context of a complete settlement on all of the issues in this proceedings, and specifically the agreed-upon changes to the proposed revenue requirement, and the uncertainty on the final costs of the project, subject to the conditions and adjustments expressly noted in this Settlement Proposal, the Parties agree to a modified approach to InnPower's request to use a deferral account to track a portion of the capital contributions made for the Barrie Area Transformer Upgrade (BATU) project between 2025-2027.

Background

On April 3, 2020, HONI received approval from the OEB in EB-2018-0117 for leave to construct transmission facilities that will increase transmission and transformation capacity to accommodate load growth in the Barrie/Innisfil area of Ontario. The transmission line and station work are collectively referred to as the BATU Project.

The capital contribution installment payments to HONI are for the incremental costs relative to the cost of the avoided sustainment work that HONI was originally planning to undertake on these facilities. At the time of the OEB decision, the total cost estimate of the BATU project was $91M, and InnPower's total capital contribution was set at $14.1M. HONI requested to the extend the capital contribution payment period from five years to 15 years in which InnPower would have made installment payments to HONI for the BATU Project. For the reasons set out in Exhibit B, Tab 9, Schedule 1 of HONI's application in EB-2018-0117, this loan methodology was estimated to save ratepayers over $2 million over the fifteen-year capital contribution payable period. The loan methodology was summarized by the OEB as follows:

> The Loan Methodology will record the net cost (excluding the full capital contribution) of the BATU Project in Hydro One's rate base once in-service, while InnPower will record its capital contribution payments in its rate base as it is paid. The deferral of the capital contribution payment from InnPower will be treated as a loan – a position OEB staff agreed with in its submission.

The OEB rejected the 15-year request and accepted a five-year capital contribution installment period at page 14 of Decision and Order EB-2018-0117 (April 23, 2020):

> Although the five-year term for capital contribution does not require OEB approval in accordance with section 6.3.19 of the TSC, the OEB makes note that the OEB accepts the five-year capital contribution installment period in light of consideration of a 15 year term in the original application.

On June 30, 2022, HONI filed a letter in EB-2018-0117 providing an update to the BATU Project's schedule and forecast cost. HONI advised the OEB that the BATU Project is now expected to be in-service December 2023 and total forecast cost was revised to $125.0M. As a result, InnPower's capital contribution increased to an estimated $20.6 million. The capital contribution estimate is based on April 2022 cost estimates provided by the Hydro One contractor.

The capital contribution associated the BATU project accounts for approximately 82% of InnPower's proposed net System Service costs over the 2024-2028 forecast period

Payments will be made annually to HONI with interest at the OEB construction work-in-progress rate, over five (5) years after energization.

BATU Installment Account

InnPower proposed a BATU Installment Deferral Account to capture the revenue requirement associated with its capital contribution installments paid to HONI for its proportionate share of the BATU Project as approved, and subsequently updated, in EB-2018-0117. The account would not capture the capital contribution installment paid in 2023 and the portion of the 2024 capital contribution installment paid which has been entered into rate base in the 2024 Test Year in accordance with the Half-Year Rule.

The BATU Installment Deferral Account only concerns incremental revenue requirement associated with capital contribution installment payments paid by InnPower for the BATU Project for: (i) a half year in 2024 due to the OEB half year rule; and (ii) 2025 to 2027 (Incentive Period Payments). It is currently estimated that the total value of the Incentive Period Payments will total $14,420,000. Installment payments in 2023 and half of the payment in 2024 have been incorporated into InnPower's rate base in the 2024 Test Year and are currently estimated at $6,180,000.

As part of this settlement, the Parties agree to a modified BATU Instalment Deferral Account which would record for later final disposition: (i) 50% of the revenue requirement for the Incentive Period Payments; (ii) 50% of the revenue requirement for actual installment payments as a result of variances in actual and estimated BATU Project costs; (iii) 100% of the revenue requirement impact of any BATU Project delays; and (iv) differences between the rate rider revenue collected and the approved amount for disposition.. For clarity, the Parties agree that InnPower's collection of 50% of the revenue requirement does not indicate the prudence of the capital contribution installments paid to HONI for its proportionate share of the BATU Project, which will be assessed on final disposition.

Parties agree to the creation of the modified BATU Installment Deferral Account, subject to the following additional conditions and adjustments:

- InnPower shall dispose of the BATU Installment Deferral Account on an interim basis at each IRM proceeding until the next rebasing to avoid accumulation of a significant debit balance and result in significant future rate impacts. The BATU Installment Deferral Account will be reviewed and disposed of on a final basis at the next rebasing. If any BATU capital contributions paid to Hydro One, including those include in base rates, are or should have, been delayed as a result of the in-service date of the BATU Project being in 2024 or later, then the BATU Installment Account will credit customers the full revenue requirement impact of that delay. To the degree timing delays result in such credits being made to the BATU Installment Deferral Account, review and disposition of these amounts will take place when the BATU Installment Deferral Account is reviewed and disposed of on a final basis.

<u>Operation of BATU Installment Deferral Account</u>

The sub-accounts in the BATU Installment Deferral Account will operate as follows to allow InnPower to recover from customers 50% of the revenue requirement associated with the capital contribution installment payments paid by InnPower for the BATU project for a half year in 2024, due to the OEB half year rule, and for the period between 2025 to 2027:

1. On an annual basis, a revenue requirement will be calculated associated with Incentive Period Payments. Depreciation expense, interest, return on equity, and PILs will be determined using parameters consistent with those approved in EB-2023-0033. Please refer to Schedule A in the Accounting Order for the calculation of the incremental revenue requirement impact;
2. 50% of the revenue requirement calculation in the above will be debited to the Revenue Requirement Impact sub-account for future recovery from ratepayers and credit Account 4080 – Distribution Revenue Account;
3. As balances accumulate in the Revenue Requirement Impact sub-account, interest will be calculated using the OEB's "Approved Deferral and Variance Accounts – Prescribed Interest Rate" issued quarterly and debited to sub-account Carrying Charges;
4. Beginning as early as 2026 rates, InnPower will apply for interim disposition of amounts in the Revenue Requirement Impact and Carrying Charges sub-accounts. The disposition amounts will be used to inform rate riders for collection of amounts owed to InnPower. As BATU rate rider revenues are collected, such amounts will be credited to the Rate Rider Revenues sub-account;
5. Balances in the Rate Rider Revenues sub-account will incur interest at the OEB's "Approved Deferral and Variance Accounts – Prescribed Interest Rate" issued quarterly, and such interest will be recorded in sub-account Carrying Charges;
6. As part of InnPower's next Cost of Service application, the utility will request final disposition of amounts recorded to date in the Revenue Requirement Impact sub-account. These amounts would have previously received only interim approval from the OEB;
7. On recovery of all balances in the Revenue Requirement Impact and Carrying Charges sub-accounts, which may be as late as the 2030 rate year, InnPower will seek disposition of any variance between the combined balances of Revenue Requirement Impact, Rate Rider

Revenues, and Carrying Charges, such that amounts owed to InnPower (or to ratepayers) are equal to amounts collected via rate riders.

8. At the next rebasing InnPower shall provide a detailed accounting true-up of all BATU installment payments to allow for a full reconciliation.

Evidence:

Application:

- Exhibit 2
    - 2.5.7 Advanced Capital Module

IRRs:

- 2-Staff-38, 2-Staff-39, 2-SEC-24, 2-SEC-25, 4-SEC-33, 2.0-VECC-6

Appendices to this Settlement Proposal: Appendix G – BATU DVA Accounting Order

Settlement Models: N/A

Clarification Responses:

- 2-Staff-77, 2-Staff-78, SEC-1

Supporting Parties: SEC, VECC.

Parties Taking No Position: HONI.

7. Other

7.1 Is the proposed effective date appropriate?

Complete Settlement: The Parties agree that the effective date for 2024 rates shall be January 1, 2024.

Evidence:

Application:
- Exhibit 1-1-4, section 11

IRRs:
- 2-Staff-39(a)

Appendices to this Settlement Proposal: N/A

Settlement Models: N/A

Clarification Responses: N/A

Supporting Parties: SEC, VECC.

Parties Taking No Position: HONI.

7.2 Has InnPower responded appropriately to all relevant OEB directions from previous proceedings?

Complete Settlement: The Parties agree that InnPower has responded appropriately to all relevant OEB directions from previous proceedings.

Evidence:

Application:

- Exhibit 1
  - 1.1.4.1.14 Board Directive from Previous Decision

IRRs:

- 1-Staff-3

Appendices to this Settlement Proposal: N/A

Settlement Models: N/A

Clarification Responses: N/A

Supporting Parties: SEC, VECC.

Parties Taking No Position: HONI.

8. Appendices

Appendix A – Updated 2023 Revenue Requirement Work Form

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2024 Filers

Version 1.10

Utility Name	InnPower Corporation
Service Territory	Innisfil and South Barrie
Assigned EB Number	EB-2023-0033
Name and Title	Laura Hampton, Manager of Regulatory Affairs
Phone Number	(249) 733-4190
Email Address	laurah@innpower.ca
Test Year	2024
Bridge Year	2023
Last Rebasing Year	2017

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.

For 2023 filers, the RRWF has been enhanced with an additional column, so that two stages of processing of an application (e.g. interrogatory responses and settlement agreement) between the initial application filing and the OEB decision and draft rate order ("Per Board Decision") can be used. Functionality of the RRWF is the same as in previous versions of the RRWF. (May 2022)

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 results.

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2024 Filers

Table of Contents

Notes:

(1) Pale green cells represent inputs
(2) Pale green boxes at the bottom of each page are for additional notes
(3) Pale blue 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.***

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2024 Filers

Data Input Sheet [1]

		Initial Application [2]	Adjustments	Interrogatory Responses [6]	Adjustments	Settlement Agreement [6]	Adjustments	Per Board Decision
1	**Rate Base**							
	Gross Fixed Assets (average)	$ 96,234,337	$ -	$ 96,234,337	($1,888,023)	$ 94,346,314		$ 94,346,314
	Accumulated Depreciation (average)	($22,456,566) (5)	($157,149)	$ (22,613,715)	($17,409)	$ (22,631,124)		$ (22,631,124)
	Allowance for Working Capital:							
	Controllable Expenses	$8,456,798	$ -	$ 8,456,798	($750,000)	$ 7,706,798		$ 7,706,798
	Cost of Power	$31,662,671	$650,983	$ 32,313,654	$1,443,129	$ 33,756,783		$ 33,756,783
	Working Capital Rate (%)	7.50% (9)	0.00%	7.50% (9)	0.00%	7.50% (9)		(9)
2	**Utility Income**							
	Operating Revenues:							
	Distribution Revenue at Current Rates	$14,114,157	$412,541	$14,526,697	$57,797	$14,584,495		
	Distribution Revenue at Proposed Rates	$14,421,850	$500,309	$14,922,159	($1,027,889)	$13,894,270		
	Other Revenue:							
	Specific Service Charges	$258,228	$0	$258,228	$0	$258,228		
	Late Payment Charges	$139,200	$0	$139,200	$0	$139,200		
	Other Distribution Revenue	$94,086	$0	$94,086	$681	$94,766		
	Other Income and Deductions	$3,445,970	($519,951)	$2,926,019	$149,407	$3,075,426		
	Total Revenue Offsets	$3,937,483 (7)	($519,951)	$3,417,532	$150,088	$3,567,620		
	Operating Expenses:							
	OM+A Expenses	$8,327,618	$ -	$ 8,327,618	($750,000)	$7,577,618		$ 7,577,618
	Depreciation/Amortization	$5,027,633	$2,066	$ 5,029,700	$67,177	$5,096,877		$ 5,096,877
	Property taxes	$129,180	$ -	$ 129,180	$ -	$129,180		$ 129,180
	Other expenses		$ -					
3	**Taxes/PILs**							
	Taxable Income:							
	Adjustments required to arrive at taxable income	($2,172,511) (3)	($85,193)	($2,257,704)	($32,546)	($2,290,251)		
	Utility Income Taxes and Rates:							
	Income taxes (not grossed up)	$186,132	($23,651)	$162,481	($27,014)	$135,467		
	Income taxes (grossed up)	$253,241		$221,062		$184,309		
	Federal tax (%)	15.00%	0.00%	15.00%	0.00%	15.00%		
	Provincial tax (%)	11.50%	0.00%	11.50%	0.00%	11.50%		
	Income Tax Credits							
4	**Capitalization/Cost of Capital**							
	Capital Structure:							
	Long-term debt Capitalization Ratio (%)	56.0%	0.00%	56.0%	0.00%	56.0%		
	Short-term debt Capitalization Ratio (%)	4.0% (8)	0.00%	4.0% (8)	0.00%	4.0% (8)		(8)
	Common Equity Capitalization Ratio (%)	40.0%	0.00%	40.0%	0.00%	40.0%		
	Prefered Shares Capitalization Ratio (%)							
		100.0%		100.0%		100.0%		
	Cost of Capital							
	Long-term debt Cost Rate (%)	3.72%	0.04%	3.76%	(0.11%)	3.65%		
	Short-term debt Cost Rate (%)	4.79%	0.00%	4.79%	0.00%	4.79%		
	Common Equity Cost Rate (%)	9.36%	0.00%	9.36%	0.00%	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) Some Applicants may have a unique rate as a result of a lead-lag study. The default rate for 2024 cost of service applications is 7.5%, per the letter issued by the Board on June 3, 2015.

(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 or U12. 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. Beginning for 2023,two intermediate stages can be shown (e.g., Interrogatory Responses and Settlement Agreement).

(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 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.

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2024 Filers

Rate Base and Working Capital

Rate Base

Line No.	Particulars		Initial Application	Adjustments	Interrogatory Responses	Adjustments	Settlement Agreement	Adjustments	Per Board Decision
1	Gross Fixed Assets (average)	(2)	$96,234,337	$ -	$96,234,337	($1,888,023)	$94,346,314	$ -	$94,346,314
2	Accumulated Depreciation (average)	(2)	($22,456,566)	($157,149)	($22,613,715)	($17,409)	($22,631,124)	$ -	($22,631,124)
3	Net Fixed Assets (average)	(2)	$73,777,771	($157,149)	$73,620,622	($1,905,432)	$71,715,190	$ -	$71,715,190
4	Allowance for Working Capital	(1)	$3,008,960	$48,824	$3,057,784	$51,985	$3,109,769	($3,109,769)	$ -
5	**Total Rate Base**		$76,786,731	($108,325)	$76,678,406	($1,853,447)	$74,824,959	($3,109,769)	$71,715,190

(1) Allowance for Working Capital - Derivation

Line No.	Particulars		Initial Application	Adjustments	Interrogatory Responses	Adjustments	Settlement Agreement	Adjustments	Per Board Decision
6	Controllable Expenses		$8,456,798	$ -	$8,456,798	($750,000)	$7,706,798	$ -	$7,706,798
7	Cost of Power		$31,662,671	$650,983	$32,313,654	$1,443,129	$33,756,783	$ -	$33,756,783
8	Working Capital Base		$40,119,469	$650,983	$40,770,452	$693,129	$41,463,581	$ -	$41,463,581
9	Working Capital Rate %	(1)	7.50%	0.00%	7.50%	0.00%	7.50%	-7.50%	0.00%
10	Working Capital Allowance		$3,008,960	$48,824	$3,057,784	$51,985	$3,109,769	($3,109,769)	$ -

Notes

(1) Some Applicants may have a unique rate as a result of a lead-lag study. The default rate for 2023 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.

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2024 Filers

Utility Income

Line No.	Particulars		Initial Application	Adjustments	Interrogatory Responses	Adjustments	Settlement Agreement	Adjustments	Per Board Decision
	Operating Revenues:								
1	Distribution Revenue (at Proposed Rates)		$14,421,850	$500,309	$14,922,159	($1,027,889)	$13,894,270	$ -	$13,894,270
2	Other Revenue	(1)	$3,937,483	($519,951)	$3,417,532	$150,088	$3,567,620	$ -	$3,567,620
3	Total Operating Revenues		$18,359,333	($19,642)	$18,339,691	($877,801)	$17,461,890	$ -	$17,461,890
	Operating Expenses:								
4	OM+A Expenses		$8,327,618	$ -	$8,327,618	($750,000)	$7,577,618	$ -	$7,577,618
5	Depreciation/Amortization		$5,027,633	$2,066	$5,029,700	$67,177	$5,096,877	$ -	$5,096,877
6	Property taxes		$129,180	$ -	$129,180	$ -	$129,180	$ -	$129,180
7	Capital taxes		$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	Other expense		$ -	$ -		$ -		$ -	
9	Subtotal (lines 4 to 8)		$13,484,432	$2,066	$13,486,498	($682,823)	$12,803,675	$ -	$12,803,675
10	Deemed Interest Expense		$1,746,766	$14,525	$1,761,292	($88,832)	$1,672,460	($69,508)	$1,602,952
11	Total Expenses (lines 9 to 10)		$15,231,198	$16,592	$15,247,789	($771,654)	$14,476,135	($69,508)	$14,406,626
12	**Utility income before income taxes**		$3,128,135	($36,233)	$3,091,902	($106,147)	$2,985,755	$69,508	$3,055,263
13	Income taxes (grossed-up)		$253,241	($32,178)	$221,062	($36,754)	$184,309	$ -	$184,309
14	**Utility net income**		$2,874,895	($4,055)	$2,870,839	($69,393)	$2,801,446	$69,508	$2,870,955

Notes

Other Revenues / Revenue Offsets

Note	Particulars	Initial Application	Adjustments	Interrogatory Responses	Adjustments	Settlement Agreement	Adjustments	Per Board Decision
(1)	Specific Service Charges	$258,228	$ -	$258,228	$ -	$258,228		$258,228
	Late Payment Charges	$139,200	$ -	$139,200	$ -	$139,200		$139,200
	Other Distribution Revenue	$94,086	$ -	$94,086	$681	$94,766		$94,766
	Other Income and Deductions	$3,445,970	($519,951)	$2,926,019	$149,407	$3,075,426		$3,075,426
	Total Revenue Offsets	$3,937,483	($519,951)	$3,417,532	$150,088	$3,567,620	$ -	$3,567,620

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2024 Filers

Taxes/PILs

Line No.	Particulars	Application	Interrogatory Responses	Settlement Agreement	Per Board Decision
	Determination of Taxable Income				
1	Utility net income before taxes	$2,874,895	$2,870,840	$2,801,446	$2,685,017
2	Adjustments required to arrive at taxable utility income	($2,172,511)	($2,257,704)	($2,290,251)	($2,290,251)
3	Taxable income	$702,384	$613,135	$511,196	$394,766
	Calculation of Utility income Taxes				
4	Income taxes	$186,132	$162,481	$135,467	$135,467
6	Total taxes	$186,132	$162,481	$135,467	$135,467
7	Gross-up of Income Taxes	$67,109	$58,582	$48,842	$48,842
8	Grossed-up Income Taxes	$253,241	$221,062	$184,309	$184,309
9	PILs / tax Allowance (Grossed-up Income taxes + Capital taxes)	$253,241	$221,062	$184,309	$184,309
10	Other tax Credits	$ -	$ -	$ -	$ -
	Tax Rates				
11	Federal tax (%)	15.00%	15.00%	15.00%	15.00%
12	Provincial tax (%)	11.50%	11.50%	11.50%	11.50%
13	Total tax rate (%)	26.50%	26.50%	26.50%	26.50%

Notes

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2024 Filers

Capitalization/Cost of Capital

Line No.	Particulars	Capitalization Ratio (%)	Capitalization Ratio ($)	Cost Rate (%)	Return ($)
	Initial Application				
	Debt				
1	Long-term Debt	56.00%	$43,000,570	3.72%	$1,599,643
2	Short-term Debt	4.00%	$3,071,469	4.79%	$147,123
3	**Total Debt**	60.00%	$46,072,039	3.79%	$1,746,766
	Equity				
4	Common Equity	40.00%	$30,714,693	9.36%	$2,874,895
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	40.00%	$30,714,693	9.36%	$2,874,895
7	**Total**	100.00%	$76,786,731	6.02%	$4,621,661
	Interrogatory Responses				
	Debt				
1	Long-term Debt	56.00%	$42,939,907	3.76%	$1,614,376
2	Short-term Debt	4.00%	$3,067,136	4.79%	$146,916
3	**Total Debt**	60.00%	$46,007,044	3.83%	$1,761,292
	Equity				
4	Common Equity	40.00%	$30,671,362	9.36%	$2,870,840
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	40.00%	$30,671,362	9.36%	$2,870,840
7	**Total**	100.00%	$76,678,406	6.04%	$4,632,131
	Settlement Agreement				
	Debt				
8	Long-term Debt	56.00%	$41,901,977	3.65%	$1,529,095
9	Short-term Debt	4.00%	$2,992,998	4.79%	$143,365
10	**Total Debt**	60.00%	$44,894,975	3.73%	$1,672,460
	Equity				
11	Common Equity	40.00%	$29,929,983	9.36%	$2,801,446
12	Preferred Shares	0.00%	$ -	0.00%	$ -
13	**Total Equity**	40.00%	$29,929,983	9.36%	$2,801,446
14	**Total**	100.00%	$74,824,959	5.98%	$4,473,906
	Per Board Decision				
	Debt				
8	Long-term Debt	56.00%	$40,160,506	3.65%	$1,465,545
9	Short-term Debt	4.00%	$2,868,608	4.79%	$137,406
10	**Total Debt**	60.00%	$43,029,114	3.73%	$1,602,952
	Equity				
11	Common Equity	40.00%	$28,686,076	9.36%	$2,685,017
12	Preferred Shares	0.00%	$ -	0.00%	$ -
13	**Total Equity**	40.00%	$28,686,076	9.36%	$2,685,017
14	**Total**	100.00%	$71,715,190	5.98%	$4,287,968

Notes

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2024 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	Settlement Agreement: At Current Approved Rates	Settlement Agreement: At Proposed Rates	Per Board Decision: At Current Approved Rates	Per Board Decision: At Proposed Rates
1	Revenue Deficiency from Below		$307,694		$395,462		($690,225)		($92,404)
2	Distribution Revenue	$14,114,157	$14,114,156	$14,526,697	$14,526,697	$14,584,495	$14,584,494	$14,584,495	$13,986,674
3	Other Operating Revenue Offsets - net	$3,937,483	$3,937,483	$3,417,532	$3,417,532	$3,567,620	$3,567,620	$3,567,620	$3,567,620
4	**Total Revenue**	$18,051,640	$18,359,333	$17,944,229	$18,339,691	$18,152,115	$17,461,890	$18,152,115	$17,461,890
5	Operating Expenses	$13,484,432	$13,484,432	$13,486,498	$13,486,498	$12,803,675	$12,803,675	$12,803,675	$12,803,675
6	Deemed Interest Expense	$1,746,766	$1,746,766	$1,761,292	$1,761,292	$1,672,460	$1,672,460	$1,602,952	$1,602,952
8	**Total Cost and Expenses**	$15,231,198	$15,231,198	$15,247,789	$15,247,789	$14,476,135	$14,476,135	$14,406,626	$14,406,626
9	**Utility Income Before Income Taxes**	$2,820,442	$3,128,135	$2,696,440	$3,091,902	$3,675,980	$2,985,755	$3,745,488	$3,055,263
10	Tax Adjustments to Accounting Income per 2013 PILs model	($2,172,511)	($2,172,511)	($2,257,704)	($2,257,704)	($2,290,251)	($2,290,251)	$ -	($2,290,251)
11	**Taxable Income**	$647,931	$955,624	$438,736	$834,198	$1,385,729	$695,504	$3,745,488	$765,013
12	Income Tax Rate	26.50%	26.50%	26.50%	26.50%	26.50%	26.50%	26.50%	26.50%
13	**Income Tax on Taxable Income**	$171,702	$253,240	$116,265	$221,062	$367,218	$184,309	$992,554	$202,728
14	**Income Tax Credits**	$ -	$ -	$ -	$ -	$ -	$ -		
15	**Utility Net Income**	$2,648,740	$2,874,895	$2,580,175	$2,870,839	$3,308,762	$2,801,446	$2,752,934	$2,870,955
16	**Utility Rate Base**	$76,786,731	$76,786,731	$76,678,406	$76,678,406	$74,824,959	$74,824,959	$71,715,190	$71,715,190
17	Deemed Equity Portion of Rate Base	$30,714,693	$30,714,693	$30,671,362	$30,671,362	$29,929,983	$29,929,983	$28,686,076	$28,686,076
18	Income/(Equity Portion of Rate Base)	8.62%	9.36%	8.41%	9.36%	11.06%	9.36%	9.60%	10.01%
19	Target Return - Equity on Rate Base	9.36%	9.36%	9.36%	9.36%	9.36%	9.36%	9.36%	9.36%
20	Deficiency/Sufficiency in Return on Equity	-0.74%	0.00%	-0.95%	0.00%	1.70%	0.00%	0.24%	0.65%
21	Indicated Rate of Return	5.72%	6.02%	5.66%	6.04%	6.66%	5.98%	6.07%	6.24%
22	Requested Rate of Return on Rate Base	6.02%	6.02%	6.04%	6.04%	5.98%	5.98%	5.98%	5.98%
23	Deficiency/Sufficiency in Rate of Return	-0.29%	0.00%	-0.38%	0.00%	0.68%	0.00%	0.09%	0.26%
24	Target Return on Equity	$2,874,895	$2,874,895	$2,870,840	$2,870,840	$2,801,446	$2,801,446	$2,685,017	$2,685,017
25	Revenue Deficiency/(Sufficiency)	$226,155	($0)	$290,665	($0)	($507,315)	($0)	($67,917)	$185,938
26	**Gross Revenue Deficiency/(Sufficiency)**	$307,694 (1)		$395,462 (1)		($690,225) (1)		($92,404) (1)	

Notes:

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

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2024 Filers

Revenue Requirement

Line No.	Particulars	Application		Interrogatory Responses		Per Board Decision		Per Board Decision	
1	OM&A Expenses	$8,327,618		$8,327,618		$7,577,618		$7,577,618	
2	Amortization/Depreciation	$5,027,633		$5,029,700		$5,096,877		$5,096,877	
3	Property Taxes	$129,180		$129,180		$129,180		$129,180	
5	Income Taxes (Grossed up)	$253,241		$221,062		$184,309		$184,309	
6	Other Expenses	$ -							
7	Return								
	Deemed Interest Expense	$1,746,766		$1,761,292		$1,672,460		$1,602,952	
	Return on Deemed Equity	$2,874,895		$2,870,840		$2,801,446		$2,685,017	
8	**Service Revenue Requirement (before Revenues)**	$18,359,333		$18,339,691		$17,461,890		$17,275,952	
9	Revenue Offsets	$3,937,483		$3,417,532		$3,567,620		$ -	
10	**Base Revenue Requirement (excluding Tranformer Owership Allowance credit adjustment)**	$14,421,850		$14,922,159		$13,894,270		$17,275,952	
11	Distribution revenue	$14,421,850		$14,922,159		$13,894,270		$13,894,270	
12	Other revenue	$3,937,483		$3,417,532		$3,567,620		$3,567,620	
13	**Total revenue**	$18,359,333		$18,339,691		$17,461,890		$17,461,890	
14	**Difference (Total Revenue Less Distribution Revenue Requirement before Revenues)**	($0)	(1)	($0)	(1)	($0)	(1)	$185,938	(1)

Summary Table of Revenue Requirement and Revenue Deficiency/Sufficiency

	Application	Interrogatory Responses	Δ% (2)	Per Board Decision	Δ% (2)	Per Board Decision	Δ% (2)
Service Revenue Requirement	$18,359,333	$18,339,691	###	$17,461,890	(4.89%)	$17,275,952	(5.90%)
Grossed-Up Revenue Deficiency/(Sufficiency)	$307,694	$395,462	###	($690,225)	#######	($92,404)	(130.03%)
Base Revenue Requirement (to be recovered from Distribution Rates)	$14,421,850	$14,922,159	###	$13,894,270	(3.66%)	$17,275,952	19.79%
Revenue Deficiency/(Sufficiency) Associated with Base Revenue Requirement	$307,693	$395,462	###	($690,225)	#######	$ -	(100.00%)

Notes

(1) Line 11 - Line 8

(2) Percentage Change Relative to Initial Application

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2024 Filers

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: Settlement Agreement

	Customer Class	Initial Application			Interrogatory Responses			Settlement Agreement			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	**Customer / Connections** Test Year average or mid-year	**kWh** Annual	**kW/kVA** [1] Annual
1	Residential	19,957	190,211,161		20,636	195,560,391		20,736	196,515,750	-			
2	GS<50 kW	1,324	45,901,003		1,314	43,470,009		1,314	43,471,713	-			
3	GS 50 to 4999 kW	80	56,653,142	152,108	87	59,687,033	156,827	87	59,688,867	156,832			
4	Sentinel Lighting	147	95,254	263	149	96,591	267	149	96,591	267			
5	Street Lighting	4,334	869,952	2,623	4,460	895,336	2,674	4,460	895,336	2,674			
6	Unmetered Scattered Load	71	441,081		75	466,609		75	466,609	-			
7	Embedded Distributor	1	935,589	2,355	1	935,589	2,361	1	935,589	2,361			
8													
9													
10													
11													
12													
13													
14													
15													
16													
17													
18													
19													
20													
	Total		**295,107,182**	**157,348**		**301,111,558**	**162,129**		**302,070,456**	**162,134**			

Notes:

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

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2024 Filers

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: ***Settlement Agreement***

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	$ 8,064,053	79.54%	$ 13,891,076	79.55%
2	GS<50 kW	$ 835,151	8.24%	$ 1,687,481	9.66%
3	GS 50 to 4999 kW	$ 958,338	9.45%	$ 1,585,701	9.08%
4	Sentinel Lighting	$ 43,848	0.43%	$ 30,648	0.18%
5	Street Lighting	$ 194,479	1.92%	$ 232,502	1.33%
6	Unmetered Scattered Load	$ 21,269	0.21%	$ 21,095	0.12%
7	Embedded Distributor	$ 21,270	0.21%	$ 13,387	0.08%
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
	Total	$ 10,138,408	100.00%	**$ 17,461,890**	100.00%
		Service Revenue Requirement (from Sheet 9)		**$ 17,461,890.08**	

(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	LF X current approved rates X (1+d)	LF X Proposed Rates	Miscellaneous Revenues
		(7B)	(7C)	(7D)	(7E)
1	Residential	$ 10,972,014	$ 11,409,616	$ 11,409,280	$ 2,919,063
2	GS<50 kW	$ 1,358,579	$ 1,158,491	$ 1,158,504	$ 328,902
3	GS 50 to 4999 kW	$ 1,346,890	$ 930,172	$ 1,050,897	$ 238,811
4	Sentinel Lighting	$ 23,484	$ 43,208	$ 29,614	$ 7,164
5	Street Lighting	$ 165,477	$ 316,240	$ 211,971	$ 67,025
6	Unmetered Scattered Load	$ 16,300	$ 23,055	$ 20,518	$ 4,796
7	Embedded Distributor	$ 11,527	$ 13,486	$ 13,486	$ 1,860
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
	Total	$ 13,894,270	$ 13,894,270	$ 13,894,270	$ 3,567,620

(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:	Status Quo Ratios (7C + 7E) / (7A)	Proposed Ratios (7D + 7E) / (7A)	Policy Range
		%	%	%	%
1	Residential	99.44	103.15%	103.15%	85 - 115
2	GS<50 kW	103.54	88.14%	88.14%	
3	GS 50 to 4999 kW	98.41	73.72%	81.33%	
4	Sentinel Lighting	102.71	164.36%	120.00%	
5	Street Lighting	120.00	164.84%	120.00%	
6	Unmetered Scattered Load	98.41	132.02%	120.00%	
7	Embedded Distributor	99.41	114.64%	114.63%	
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
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 2019 with further adjustments to move within the range over two years, the most recent year would be 2022. However, the ratios in 2022 would be equal to those after the adjustment in 2021.

(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		
			1	2	
1	Residential	103.15%	103.15%	103.15%	85 - 115
2	GS<50 kW	88.14%	88.14%	88.14%	
3	GS 50 to 4999 kW	81.33%	81.33%	81.33%	
4	Sentinel Lighting	120.00%	120.00%	120.00%	
5	Street Lighting	120.00%	120.00%	120.00%	
6	Unmetered Scattered Load	120.00%	120.00%	120.00%	
7	Embedded Distributor	114.63%	114.63%	114.63%	
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					

(11) The applicant should complete Table D if it is applying for approval of a revenue-to-cost ratio in 2024 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 2025 and 2026 Price Cap IR models, as necessary. For 2025 and 2026, enter the planned revenue-to-cost ratios that will be "Change" or "No Change" in 2025 (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'.

Revenue Requirement Workform (RRWF) for 2024 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: *Settlement Agreement*

Customer and Load Forecast / **Class Allocated Revenues** (From Sheet 11. Cost Allocation and Sheet 12. Residential Rate Design)

	Customer Class (From sheet 10. Load Forecast)	Volumetric Charge Determinant	Customers / Connections	kWh	kW or kVA	Total Class Revenue Requirement	Monthly Service Charge	Volumetric
1	Residential	kWh	20,736	196,515,750	-	$ 11,409,280	$ 11,409,280	$ 0
2	GS<50 kW	kWh	1,314	43,471,713	-	$ 1,158,504	$ 729,158	$ 429,346
3	GS 50 to 4999 kW	kW	87	59,688,867	156,832	$ 1,050,897	$ 247,180	$ 803,717
4	Sentinel Lighting	kW	149	96,591	267	$ 29,614	$ 17,621	$ 11,994
5	Street Lighting	kW	4,460	895,336	2,674	$ 211,971	$ 157,555	$ 54,416
6	Unmetered Scattered Load	kWh	75	466,609	-	$ 20,518	$ 10,983	$ 9,534
7	Embedded Distributor	kW	1	935,589	2,361	$ 13,486	$ 2,704	$ 10,782
8			-	-	-			
9			-	-	-			
10			-	-	-			
11			-	-	-			
12			-	-	-			
13			-	-	-			
14			-	-	-			
15			-	-	-			
16			-	-	-			
17			-	-	-			
18			-	-	-			
19			-	-	-			
20			-	-	-			

Fixed / Variable Splits [2,3] (Percentage to be entered as a fraction between 0 and 1) / **Distribution Rates** / **Revenue Reconciliation**

	Customer Class	Fixed	Variable	Transformer Ownership Allowance [1] ($)	Monthly Service Charge [2] Rate	Monthly Service Charge No. of decimals	Volumetric Rate [3] Rate		Volumetric Rate No. of decimals	MSC Revenues	Volumetric revenues	Revenues less Transformer Ownership Allowance
1	Residential	100.00%	0.00%		$45.85	2	$0.0000	/kWh	4	$ 11,409,068.39	$ -	$ 11,409,068.39
2	GS<50 kW	62.94%	37.06%		$46.24		$0.0099	/kWh		$ 729,157.74	$ 430,369.9604	$ 1,159,527.70
3	GS 50 to 4999 kW	23.52%	76.48%	$ 22,494	$236.52		$5.2681	/kW		$ 247,179.98	$ 826,205.5395	$ 1,050,891.28
4	Sentinel Lighting	59.50%	40.50%		$9.85		$44.8815	/kW		$ 17,627.06	$ 11,993.5094	$ 29,620.56
5	Street Lighting	74.33%	25.67%		$2.94		$20.3515	/kW		$ 157,352.87	$ 54,416.2121	$ 211,769.08
6	Unmetered Scattered Load	53.53%	46.47%		$12.13		$0.0204	/kWh		$ 10,981.57	$ 9,518.8306	$ 20,500.40
7	Embedded Distributor	20.05%	79.95%		$225.32		$4.5660	/kW		$ 2,703.84	$ 10,781.9634	$ 13,485.80
8										$ -	$ -	$ -
9										$ -	$ -	$ -
10										$ -	$ -	$ -
11										$ -	$ -	$ -
12										$ -	$ -	$ -
13										$ -	$ -	$ -
14										$ -	$ -	$ -
15										$ -	$ -	$ -
16										$ -	$ -	$ -
17										$ -	$ -	$ -
18										$ -	$ -	$ -
19										$ -	$ -	$ -
20										$ -	$ -	$ -

Total Transformer Ownership Allowance $ 22,494

Total Distribution Revenues	$13,894,863.21
Base Revenue Requirement	$13,894,269.90
Difference	$ 593.31
% Difference	0.004%

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 calcuated as: [MSC x (average number of customers or connections) x 12 months] / (Class Allocated Revenue Requirement).

3 The Volumetric rate is calculated as [(allocated volumetric revenue requirement for the class + transformer allowance credit for the class)/(annual estimate of the charge determinant for the test year (either kW or kVA for demand-billed customer classes, or kWh for non-demand-billed classes)]

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2024 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	$ 4,621,661	6.02%	$ 76,786,731	$ 40,119,469	$ 3,008,960	$ 5,027,633	$ 253,241	$ 8,327,618	$ 18,359,333	$ 3,937,483	$ 14,421,850	$ 307,694
1	2-Staff-4, 2-Staff-35, 6-Staff-62, 9-Staff-68	update 2023 capital to YTD + forecast & remove non-regulated amortization of building	$ 4,641,624	6.02%	$ 73,620,622	$ 40,770,452	$ 3,057,784	$ 5,029,700	$ 221,062	$ 8,327,618	$ 18,347,118	$ 3,937,483	$ 14,409,635	-$ 114,941
		Change	$ 19,963	0.00%	-$ 3,166,109	$ 650,983	$ 48,824	$ 2,067	-$ 32,178	$ -	-$ 12,215	$ -	-$ 12,215	-$ 422,635
2	5-Staff-60, 5-SEC-38, 3-VECC-9, 5-VECC-25	adjust cost of power/load forecast & remove 2022 loan	$ 4,632,131	6.04%	$ 73,620,622	$ 40,770,452	$ 3,057,784	$ 5,029,700	$ 221,062	$ 8,327,618	$ 18,339,691	$ 3,937,483	$ 14,402,373	-$ 124,324
		Change	-$ 9,493	0.02%	$ -	-$ 0	-$ 0	$ -	$ -	$ -	-$ 7,427	$ -	-$ 7,262	-$ 9,383
3	9.0-VECC-44	update cost allocation between OM&A accounts	$ 4,632,131	6.04%	$ 73,620,622	$ 40,770,452	$ 3,057,784	$ 5,029,700	$ 221,062	$ 8,327,618	$ 18,339,691	$ 3,937,483	$ 14,402,373	-$ 124,324
		Change	$ -	0.00%	$ -	-$ 0	-$ 0	-$ 0	$ -	$ -	$ -	$ -	-$ 0	-$ 0
4	4-Staff-53	update shared services revenue and expenses	$ 4,632,131	6.04%	$ 73,620,622	$ 40,770,452	$ 3,057,784	$ 5,029,700	$ 221,062	$ 8,327,618	$ 18,339,691	$ 3,417,532	$ 14,922,159	$ 395,462
		Change	$ -	0.00%	$ -	$ 0	$ 0	$ 0	$ -	$ -	$ -	-$ 519,951	$ 519,786	$ 519,786
5	4-Staff-59	update cost allocation between OM&A accounts	$ 4,632,131	6.04%	$ 73,620,622	$ 40,770,452	$ 3,057,784	$ 5,029,700	$ 221,062	$ 8,327,618	$ 18,339,691	$ 3,417,532	$ 14,922,159	$ 395,462
		Change	$ -	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	SEC-1	updated WIP and Capital balances	$ 4,632,131	6.04%	$ 76,678,406	$ 40,770,452	$ 3,057,784	$ 5,029,700	$ 221,062	$ 8,327,618	$ 18,339,691	$ 3,417,532	$ 14,922,159	$ 395,462
		Change	$ -	0.00%	$ 3,057,784	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
7	Settlement	updated Capital, OM&A, Load Forecast, COP, PILS balances	$ 4,467,886	5.98%	$ 74,724,276	$ 40,121,142	$ 3,009,086	$ 5,096,877	$ 182,950	$ 7,577,618	$ 17,454,511	$ 3,579,818	$ 13,874,693	-$ 709,802
		Change	-$ 164,245	-0.06%	-$ 1,954,130	-$ 649,310	-$ 48,698	$ 67,177	-$ 38,112	-$ 750,000	-$ 885,180	$ 162,286	-$ 1,047,466	-$ 1,105,264
8	OEB Rate Update	updated RSC, pole attachment, UTRs	$ 4,473,906	5.98%	$ 74,824,959	$ 41,463,581	$ 3,109,769	$ 5,096,877	$ 184,309	$ 7,577,618	$ 17,461,890	$ 3,567,620	$ 13,894,270	-$ 690,225
		Change	$ 6,020	0.00%	$ 100,683	$ 1,342,439	$ 100,683	$ -	$ 1,359	-$ 0	$ 7,379	-$ 12,198	$ 19,577	$ 19,577

Appendix B - Appendix 2-AB: Capital Expenditure Summary

File Number:	EB-2023-0033
Exhibit:	2
Tab:	5
Schedule:	2
Page:	3
Date:	2023-05-12

TO BE UPDATED AT THE DRAFT RATE ORDER STAGE

Capital Expnditures = In Service Additions

Appendix 2-AB

Table 2 - Capital Expenditure Summary from Chapter 5 Consolidated Distribution System Plan Filing Requirements

First year of Forecast Period:

2024

CATEGORY	Historical Period (previous plan[1] & actual)																					Forecast Period (planned)				
	2017			2018			2019			2020			2021			2022			2023			2024	2025	2026	2027	2028
	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual[2]	Var					
	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000				
System Access	3,509	1,523	-56.6%	13,778	2,096	-84.8%	11,682	5,169	-55.8%	12,103	7,640	-36.9%	13,192	8,945	-32.2%		3,856	--	23,957		-100.0%	30,350	17,381	9,584	8,624	8,875
System Renewal	1,348	2,553	89.3%	1,142	1,908	67.0%	3,326	1,495	-55.0%	2,862	2,006	-29.9%	2,577	1,798	-30.2%		8,042	--	11,686		-100.0%	7,258	1,593	1,633	1,674	1,716
System Service	248	21	-91.5%	660	276	-58.2%	393	2,273	478.4%	534	2,737	412.5%	422	2,412	471.6%		503	--	11,511		-100.0%	16,313	24,180	26,292	29,856	29,668
General Plant	1,168	307	-73.7%	1,423	1,147	-19.4%	962	444	-53.9%	745	876	17.6%	706	1,363	93.0%		1,045	--	1,851		-100.0%	1,182	730	803	821	1,035
TOTAL	6,274	4,404	-29.8%	17,003	5,426	-68.1%	16,362	9,381	-42.7%	16,244	13,259	-18.4%	16,897	14,518	-14.1%	-	13,447	--	49,006	-	-100.0%	55,103	43,884	38,312	40,975	41,293
Capital Contributions	- 1,869	- 980	-47.6%	- 11,826	- 1,360	-88.5%	- 9,928	- 6,433	-35.2%	- 10,450	- 8,545	-18.2%	- 11,129	- 7,382	-33.7%		- 8,996	--	- 37,046		-100.0%	- 37,243	- 19,898	- 7,669	- 6,997	- 7,247
NET CAPITAL EXPENDITURES	4,405	3,424	-22.3%	5,176	4,067	-21.4%	6,434	2,948	-54.2%	5,794	4,714	-18.6%	5,768	7,136	23.7%		4,451	--	11,960		-100.0%	17,860	23,986	30,643	33,978	34,047
System O&M	$ 2,179	$ 2,217	1.7%	$ 2,245	$ 2,050	-8.7%	$ 2,246	$ 1,966	-12.4%	$ 2,246	$ 1,867	-16.9%	$ 2,246	$ 2,598	15.7%		$ 2,318	--	$ 2,622		-100.0%	$ 3,091	$ 3,307	$ 3,406	$ 3,508	$ 3,614

Notes to the Table:

1. Historical "previous plan" data is not required unless a plan has previously been filed. However, use the last OEB-approved, at least on a Total (Capital) Expenditure basis for the last cost of service rebasing year, and the applicant should include their planned budget in each subsequent historical year up to and including the Bridge Year.

2. Indicate the number of months of 'actual' data included in the last year of the Historical Period (normally a 'bridge' year):

3. System O&M contains the following accounts: 5005, 5010, 5012, 5014, 5015, 5016, 5017, 5020, 5025, 5030, 5035, 5040, 5045, 5050, 5055, 5060, 5065, 5070, 5075, 5085, 5090, 5095, 5096, 5105, 5110, 5112, 5114, 5120, 5125, 5130, 5135, 5145, 5150, 5155, 5160, 5165, 5170, 5172, 5175, 5178, 5195

Explanatory Notes on Variances (complete only if applicable)
Notes on shifts in forecast vs. historical budgets by category
Notes on year over year Plan vs. Actual variances for Total Expenditures
Notes on Plan vs. Actual variance trends for individual expenditure categories
Variances are provided in the Distribution System Plan in Exhibit 2.

Appendix C - Updated Appendix 2-BA: 2023 Fixed Asset Continuity Schedules

File Number:	EB-2023-0033
Exhibit:	2
Tab:	2
Schedule:	1
Page:	1
Date:	2023-05-12

Appendix 2-BA

Fixed Asset Continuity Schedule [1]

Notes:

1 Tables in the format outlined above covering all fixed asset accounts should be submitted for the Test Year, Bridge Year and all relevant historical years. At a minimum , the applicant must provide data for the earlier of: 1) all historical years back to its last rebasing; or 2) at least three years of historical actuals, in addition to Bridge Year and Test Year forecasts. If this is the first application where the applicant is rebasing under MIFRS, contact OEB staff for further guidance on the appropriate fixed asset continuity schedules to complete (i.e. applicable years and accounting standard for each schedule).

2 The "CCA Class" for fixed assets should generally agree with the CCA Class used for tax purposes in Tax Returns. Fixed Assets sub-components may be used where the underlying asset components are classified under multiple CCA Classes for tax purposes. If an applicant uses any different classes from those shown in the table, an explanation should be provided. (also see note 3).

3 The table may need to be customized for a utility's asset categories or for any new asset accounts announced or authorized by the OEB.

4 The additions in column (E) must not include construction work in progress (CWIP).

5 Effective on the date of IFRS adoption, customer contributions will no longer be recorded in Account 1995 Contributions & Grants, but will be recorded in Account 2440, Deferred Revenues. Amortization of deferred revenue will be removed from the depreciation expense shown on this fixed asset continuity schedule as it should be included as income in Appendix 2-H Other Revenues.

6 The applicant must ensure that all asset disposals have been clearly identified in the Chapter 2 Appendices for all historic, bridge and test years. Where a distributor for general financial reporting purposes under IFRS has accounted for the amount of gain or loss on the retirement of assets in a pool of like assets as a charge or credit to income, for reporting and rate application filings, the distributor shall reclassify such gains and losses as depreciation expense, and disclose the amount separately.

7 This account includes the amount recorded under finance leases for plant leased from others and used by the utility in its utility operations.

8 The applicant must establish the continuity of historical cost for gross assets and accumulated depreciation by asset class by ensuring that the opening balance in the year agrees to the closing balance in the prior year.

Accounting Standard MIFRS
Year 2017

			Cost				Accumulated Depreciation				
CCA Class [2]	**OEB Account [3]**	**Description [3]**	**Opening Balance [8]**	**Additions [4]**	**Disposals [6]**	**Closing Balance**	**Opening Balance [8]**	**Additions**	**Disposals [6]**	**Closing Balance**	**Net Book Value**
	1609	Capital Contributions Paid	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
12	1611	Computer Software (Formally known as Account 1925)	$ 688,701	$ 94,703	$ -	$ 783,404	-$ 465,359	-$ 149,759	$ -	-$ 615,118	$ 168,286
CEC	1612	Land Rights (Formally known as Account 1906)	$ 394,446	$ -	$ -	$ 394,446	-$ 40,542	-$ 12,699	$ -	-$ 53,241	$ 341,205
N/A	1805	Land	$ 1,049,593	$ -	$ -	$ 1,049,593	$ -	$ -	$ -	$ -	$ 1,049,593
47	1808	Buildings	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ 7,282,718	$ 76,348	-$ 191,446	$ 7,167,620	-$ 552,117	-$ 253,905	$ 191,446	-$ 614,576	$ 6,553,044
47	1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 9,727,364	$ 1,321,686	-$ 11,372	$ 11,037,678	-$ 704,935	-$ 269,157	$ 2,829	-$ 971,263	$ 10,066,415
47	1835	Overhead Conductors & Devices	$ 10,914,694	$ 1,224,256	-$ 24,634	$ 12,114,316	-$ 662,189	-$ 232,973	$ 2,388	-$ 892,774	$ 11,221,542
47	1840	Underground Conduit	$ 2,978,799	$ 62,588	$ -	$ 3,041,387	-$ 243,679	-$ 96,053	$ -	-$ 339,732	$ 2,701,656
47	1845	Underground Conductors & Devices	$ 8,006,048	$ 61,020	-$ 609	$ 8,066,459	-$ 753,833	-$ 248,429	$ 609	-$ 1,001,652	$ 7,064,807
47	1850	Line Transformers	$ 5,650,378	$ 641,354	-$ 54,028	$ 6,237,704	-$ 475,913	-$ 175,459	$ 9,653	-$ 641,720	$ 5,595,984
47	1855	Services (Overhead & Underground)	$ 3,878,392	$ 363,406	$ -	$ 4,241,798	-$ 275,508	-$ 110,574	$ -	-$ 386,082	$ 3,855,716
47	1860	Meters	$ 2,295,455	$ 346,375	-$ 5,635	$ 2,636,194	-$ 542,523	-$ 212,231	$ 1,445	-$ 753,309	$ 1,882,885
47	1860	Meters (Smart Meters)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
N/A	1905	Land	$ 1,015,496	$ -	$ -	$ 1,015,496	$ -	$ -	$ -	$ -	$ 1,015,496
47	1908	Buildings & Fixtures	$ 12,438,239	$ 71,055	$ -	$ 12,509,294	-$ 416,907	-$ 271,409	$ -	-$ 688,316	$ 11,820,978
13	1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (5 years)	$ 230,265	$ 6,246	$ -	$ 236,511	-$ 58,001	-$ 25,416	$ -	-$ 83,417	$ 153,093
10	1920	Computer Equipment - Hardware	$ 498,996	$ 134,688	-$ 15,927	$ 617,757	-$ 235,520	-$ 99,128	$ 15,030	-$ 319,618	$ 298,140
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
50	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	1930	Transportation Equipment	$ 524,916	$ -	$ -	$ 524,916	-$ 349,371	-$ 100,468	$ -	-$ 449,839	$ 75,077
8	1935	Stores Equipment	$ 135,334	$ -	$ -	$ 135,334	-$ 25,481	-$ 14,248	$ -	-$ 39,729	$ 95,605
8	1940	Tools, Shop & Garage Equipment	$ 331,421	$ 19,789	$ -	$ 351,210	-$ 123,972	-$ 45,737	$ -	-$ 169,709	$ 181,501
8	1945	Measurement & Testing Equipment	$ 29,667	$ 33,848	$ -	$ 63,515	-$ 12,291	-$ 5,529	$ -	-$ 17,820	$ 45,695
8	1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communications Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1960	Miscellaneous Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1980	System Supervisor Equipment	$ 2,558,336	$ 2,963	$ -	$ 2,561,299	-$ 420,336	-$ 189,489	$ -	-$ 609,826	$ 1,951,473
47	1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1995	Contributions & Grants	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	2440	Deferred Revenue [5]	-$ 13,622,319	-$ 979,572	$ 13,154	-$ 14,588,738	$ 953,970	$ 419,035	-$ 201	$ 1,372,804	-$ 13,215,934
	2005	Property Under Finance Lease [7]	0	0	0	$ -	0	0	0	$ -	$ -
		Sub-Total	**$ 57,006,940**	**$ 3,480,751**	**-$ 290,497**	**$ 60,197,195**	**-$ 5,404,508**	**-$ 2,093,630**	**$ 223,200**	**-$ 7,274,937**	**$ 52,922,258**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)	- 2,350,000	-$ 56,055	-	-$ 2,406,055	70,499	$ 48,822	-	$ 119,321	-$ 2,286,734
		Total PP&E for Rate Base Purposes	**$ 54,656,940**	**$ 3,424,696**	**-$ 290,497**	**$ 57,791,140**	**-$ 5,334,009**	**-$ 2,044,808**	**$ 223,200**	**-$ 7,155,616**	**$ 50,635,524**
		Construction Work In Progress	$ 724,781	$ 430,110	$ -	$ 1,154,890				$ -	$ 1,154,890
		Total PP&E	**$ 55,381,721**	**$ 3,854,806**	**-$ 290,497**	**$ 58,946,031**	**-$ 5,334,009**	**-$ 2,044,808**	**$ 223,200**	**-$ 7,155,616**	**$ 51,790,414**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable [6]									
		Total						**-$ 2,044,808**			

			Less: *Fully Allocated Depreciation*	
10		Transportation	Transportation	-$ 100,468
8		Stores Equipment	Stores Equipment	
47		Deferred Revenue	Deferred Revenue	$ 419,035
			Net Depreciation	**-$ 2,363,374**

Accounting Standard	MIFRS
Year	**2018**

			Cost				Accumulated Depreciation				
CCA Class [2]	**OEB Account [3]**	**Description [3]**	**Opening Balance [8]**	**Additions [4]**	**Disposals [6]**	**Closing Balance**	**Opening Balance [8]**	**Additions**	**Disposals [6]**	**Closing Balance**	**Net Book Value**
	1609	Capital Contributions Paid	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
12	1611	Computer Software (Formally known as Account 1925)	$ 783,404	$ 168,705	$ -	$ 952,109	-$ 615,118	-$ 129,811	$ -	-$ 744,929	$ 207,180
CEC	1612	Land Rights (Formally known as Account 1906)	$ 394,446	$ -	$ -	$ 394,446	-$ 53,241	-$ 12,699	$ -	-$ 65,940	$ 328,506
N/A	1805	Land	$ 1,049,593	$ -	$ -	$ 1,049,593	$ -	$ -	$ -	$ -	$ 1,049,593
47	1808	Buildings	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ 7,167,620	$ 358,566	-$ 310	$ 7,525,876	-$ 614,576	-$ 256,768	$ -	-$ 871,344	$ 6,654,532
47	1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 11,037,678	$ 717,821	-$ 3,964	$ 11,751,535	-$ 971,263	-$ 291,440	$ 922	-$ 1,261,782	$ 10,489,754
47	1835	Overhead Conductors & Devices	$ 12,114,316	$ 1,420,095	-$ 4,345	$ 13,530,066	-$ 892,774	-$ 256,448	$ 832	-$ 1,148,390	$ 12,381,676
47	1840	Underground Conduit	$ 3,041,387	$ 120,702	$ -	$ 3,162,089	-$ 339,732	-$ 98,348	$ -	-$ 438,080	$ 2,724,009
47	1845	Underground Conductors & Devices	$ 8,066,459	$ 213,614	-$ 123	$ 8,279,950	-$ 1,001,652	-$ 251,863	$ 66	-$ 1,253,450	$ 7,026,500
47	1850	Line Transformers	$ 6,237,704	$ 570,444	$ -	$ 6,808,148	-$ 641,720	-$ 189,385	$ 4,405	-$ 826,699	$ 5,981,449
47	1855	Services (Overhead & Underground)	$ 4,241,798	$ 581,990	-$ 1,070	$ 4,822,717	-$ 386,082	-$ 121,258	$ 52	-$ 507,288	$ 4,315,429
47	1860	Meters	$ 2,636,194	$ 303,605	-$ 16,919	$ 2,922,880	-$ 753,309	-$ 232,679	$ 4,846	-$ 981,142	$ 1,941,738
47	1860	Meters (Smart Meters)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
N/A	1905	Land	$ 1,015,496	$ -	$ -	$ 1,015,496	$ -	$ -	$ -	$ -	$ 1,015,496
47	1908	Buildings & Fixtures	$ 12,509,294	$ 196,384	$ -	$ 12,705,678	-$ 688,316	-$ 280,177	$ -	-$ 968,492	$ 11,737,185
13	1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (5 years)	$ 236,511	$ -	$ -	$ 236,511	-$ 83,417	-$ 24,463	$ -	-$ 107,881	$ 128,630
10	1920	Computer Equipment - Hardware	$ 617,757	$ 45,780	-$ 3,631	$ 659,906	-$ 319,618	-$ 103,173	$ 3,631	-$ 419,160	$ 240,746
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
50	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	1930	Transportation Equipment	$ 524,916	$ 556,736	-$ 31,192	$ 1,050,460	-$ 449,839	-$ 89,889	$ 31,192	-$ 508,536	$ 541,925
8	1935	Stores Equipment	$ 135,334	$ -	$ -	$ 135,334	-$ 39,729	-$ 14,047	$ -	-$ 53,776	$ 81,558
8	1940	Tools, Shop & Garage Equipment	$ 351,210	$ 38,364	$ -	$ 389,574	-$ 169,709	-$ 47,849	$ -	-$ 217,558	$ 172,016
8	1945	Measurement & Testing Equipment	$ 63,515	$ -	$ -	$ 63,515	-$ 17,820	-$ 6,798	$ -	-$ 24,618	$ 38,897
8	1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communications Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1960	Miscellaneous Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1980	System Supervisor Equipment	$ 2,561,299	$ 133,588	$ -	$ 2,694,887	-$ 609,826	-$ 186,247	$ -	-$ 796,073	$ 1,898,814
47	1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1995	Contributions & Grants	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	2440	Deferred Revenue[5]	-$ 14,588,738	-$ 1,359,844	$ 1,030	-$ 15,947,552	$ 1,372,804	$ 446,327	-$ 52	$ 1,819,079	-$ 14,128,472
	2005	Property Under Finance Lease[7]	$ -	0	0	$ -	$ -	0	0	$ -	$ -
		Sub-Total	**$ 60,197,195**	**$ 4,066,548**	**-$ 60,524**	**$ 64,203,219**	**-$ 7,274,937**	**-$ 2,147,014**	**$ 45,894**	**-$ 9,376,058**	**$ 54,827,162**
		Less Socialized Renewable Energy Generation Investments (input as negative)	$ -			$ -	$ -			$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)	-$ 2,406,055			-$ 2,406,055	$ 119,321	$ 48,822		$ 168,143	-$ 2,237,912
		Total PP&E for Rate Base Purposes	**$ 57,791,140**	**$ 4,066,548**	**-$ 60,524**	**$ 61,797,165**	**-$ 7,155,616**	**-$ 2,098,193**	**$ 45,894**	**-$ 9,207,915**	**$ 52,589,250**
		Construction Work In Progress	$ 1,154,890	$ 112,206	$ -	$ 1,267,096				$ -	$ 1,267,096
		Total PP&E	**$ 58,946,030**	**$ 4,178,754**	**-$ 60,524**	**$ 63,064,261**	**-$ 7,155,616**	**-$ 2,098,193**	**$ 45,894**	**-$ 9,207,915**	**$ 53,856,346**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$ 2,098,193**			

			Less: *Fully Allocated Depreciation*	
10		Transportation	Transportation	-$ 89,889
8		Stores Equipment	Stores Equipment	
47		Deferred Revenue	Deferred Revenue	$ 446,327
			Net Depreciation	**-$ 2,454,630**

Accounting Standard MIFRS
Year 2019

			Cost				Accumulated Depreciation				
CCA Class [2]	OEB Account [3]	Description [3]	Opening Balance [8]	Additions [4]	Disposals [6]	Closing Balance	Opening Balance [8]	Additions	Disposals [6]	Closing Balance	Net Book Value
	1609	Capital Contributions Paid	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
12	1611	Computer Software (Formally known as Account 1925)	$ 952,109	$ 114,859	$ -	$ 1,066,968	-$ 744,929	-$ 126,538	$ -	-$ 871,467	$ 195,501
CEC	1612	Land Rights (Formally known as Account 1906)	$ 394,446	$ 2,950	$ -	$ 397,396	-$ 65,940	-$ 12,729	$ -	-$ 78,669	$ 318,728
N/A	1805	Land	$ 1,049,593	$ -	$ -	$ 1,049,593	$ -	$ -	$ -	$ -	$ 1,049,593
47	1808	Buildings	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ 7,525,876	$ 1,472,953	$ -	$ 8,998,829	-$ 871,344	-$ 287,724	$ 165	-$ 1,158,902	$ 7,839,927
47	1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 11,751,535	$ 3,289,786	-$ 66,523	$ 14,974,799	-$ 1,261,782	-$ 335,120	$ 9,402	-$ 1,587,499	$ 13,387,300
47	1835	Overhead Conductors & Devices	$ 13,530,066	$ 1,670,013	-$ 6,959	$ 15,193,121	-$ 1,148,390	-$ 284,303	$ 1,009	-$ 1,431,684	$ 13,761,437
47	1840	Underground Conduit	$ 3,162,089	$ 343,532	$ -	$ 3,505,621	-$ 438,080	-$ 104,171	-$ 14	-$ 542,264	$ 2,963,357
47	1845	Underground Conductors & Devices	$ 8,279,950	$ 335,065	-$ 2,598	$ 8,612,418	-$ 1,253,450	-$ 258,658	$ 1,623	-$ 1,510,484	$ 7,101,933
47	1850	Line Transformers	$ 6,808,148	$ 1,038,208	-$ 10,611	$ 7,835,745	-$ 826,699	-$ 209,328	$ 12,925	-$ 1,023,103	$ 6,812,642
47	1855	Services (Overhead & Underground)	$ 4,822,717	$ 598,428	$ -	$ 5,421,145	-$ 507,288	-$ 134,459	$ -	-$ 641,748	$ 4,779,398
47	1860	Meters	$ 2,922,880	$ 186,792	-$ 6,376	$ 3,103,296	-$ 981,142	-$ 243,372	$ 2,248	-$ 1,222,266	$ 1,881,030
47	1860	Meters (Smart Meters)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
N/A	1905	Land	$ 1,015,496	$ -	$ -	$ 1,015,496	$ -	$ -	$ -	$ -	$ 1,015,496
47	1908	Buildings & Fixtures	$ 12,705,678	$ 38,914	$ -	$ 12,744,591	-$ 968,492	-$ 282,515	$ -	-$ 1,251,008	$ 11,493,583
13	1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (5 years)	$ 236,511	$ 39,714	$ -	$ 276,224	-$ 107,881	-$ 25,208	$ -	-$ 133,089	$ 143,135
10	1920	Computer Equipment - Hardware	$ 659,906	$ 45,304	-$ 1,889	$ 703,321	-$ 419,160	-$ 98,850	$ 757	-$ 517,253	$ 186,068
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
50	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	1930	Transportation Equipment	$ 1,050,460	$ 6,428	-$ 48,051	$ 1,008,837	-$ 508,536	-$ 79,104	$ 40,449	-$ 547,190	$ 461,647
8	1935	Stores Equipment	$ 135,334	$ -	$ -	$ 135,334	-$ 53,776	-$ 13,474	$ -	-$ 67,250	$ 68,085
8	1940	Tools, Shop & Garage Equipment	$ 389,574	$ 22,265	-$ 10,719	$ 401,120	-$ 217,558	-$ 49,554	$ 4,291	-$ 262,821	$ 138,299
8	1945	Measurement & Testing Equipment	$ 63,515	$ 5,225	$ -	$ 68,740	-$ 24,618	-$ 6,660	$ -	-$ 31,278	$ 37,462
8	1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communications Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1960	Miscellaneous Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1980	System Supervisor Equipment	$ 2,694,887	$ -	$ -	$ 2,694,887	-$ 796,073	-$ 183,583	$ -	-$ 979,656	$ 1,715,231
47	1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1995	Contributions & Grants	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	2440	Deferred Revenue[5]	-$ 15,947,552	-$ 6,432,656	$ -	-$ 22,380,208	$ 1,819,079	$ 540,241	$ -	$ 2,359,320	-$ 20,020,888
	2005	Property Under Finance Lease[7]	$ -	$ 170,612	$ -	$ 170,612	$ -	-$ 20,931	$ -	-$ 20,931	$ 149,681
		Sub-Total	**$ 64,203,219**	**$ 2,948,391**	**-$ 153,724**	**$ 66,997,886**	**-$ 9,376,058**	**-$ 2,216,040**	**$ 72,856**	**-$ 11,519,242**	**$ 55,478,644**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)	-$ 2,406,055			-$ 2,406,055	$ 168,143	$ 48,822		$ 216,965	-$ 2,189,090
		Total PP&E for Rate Base Purposes	**$ 61,797,165**	**$ 2,948,391**	**-$ 153,724**	**$ 64,591,832**	**-$ 9,207,915**	**-$ 2,167,218**	**$ 72,856**	**-$ 11,302,277**	**$ 53,289,554**
		Construction Work In Progress	$ 1,267,096	$ 2,469,820	$ -	$ 3,736,916				$ -	$ 3,736,916
		Total PP&E	**$ 63,064,261**	**$ 5,418,211**	**-$ 153,724**	**$ 68,328,748**	**-$ 9,207,915**	**-$ 2,167,218**	**$ 72,856**	**-$ 11,302,277**	**$ 57,026,470**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$ 2,167,218**			

			Less: *Fully Allocated Depreciation*	
10		Transportation	Transportation	-$ 100,035
8		Stores Equipment	Stores Equipment	
47		Deferred Revenue	Deferred Revenue	$ 540,241
			Net Depreciation	**-$ 2,607,425**

Accounting Standard MIFRS
Year 2020

			Cost				Accumulated Depreciation				
CCA Class [2]	**OEB Account [3]**	**Description [3]**	**Opening Balance [8]**	**Additions [4]**	**Disposals [6]**	**Closing Balance**	**Opening Balance [8]**	**Additions**	**Disposals [6]**	**Closing Balance**	**Net Book Value**
	1609	Capital Contributions Paid	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
12	1611	Computer Software (Formally known as Account 1925)	$ 1,066,968	$ 240,107	$ -	$ 1,307,075	-$ 871,467	-$ 150,767	$ -	-$ 1,022,234	$ 284,841
CEC	1612	Land Rights (Formally known as Account 1906)	$ 397,396	$ -	$ -	$ 397,396	-$ 78,669	-$ 12,793	$ -	-$ 91,462	$ 305,935
N/A	1805	Land	$ 1,049,593	$ -	$ -	$ 1,049,593	$ -	$ -	$ -	$ -	$ 1,049,593
47	1808	Buildings	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ 8,998,829	$ 3,617,853	-$ 1,201	$ 12,615,481	-$ 1,158,902	-$ 400,048	$ 28,602	-$ 1,530,348	$ 11,085,132
47	1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 14,974,799	$ 3,208,762	-$ 17,486	$ 18,166,075	-$ 1,587,499	-$ 389,142	$ 1,546	-$ 1,975,095	$ 16,190,980
47	1835	Overhead Conductors & Devices	$ 15,193,121	$ 2,310,861	-$ 31,208	$ 17,472,773	-$ 1,431,684	-$ 321,241	$ 18,441	-$ 1,734,484	$ 15,738,290
47	1840	Underground Conduit	$ 3,505,621	$ 494,242	$ -	$ 3,999,862	-$ 542,264	-$ 114,945	$ -	-$ 657,209	$ 3,342,653
47	1845	Underground Conductors & Devices	$ 8,612,418	$ 429,863	-$ 7,370	$ 9,034,911	-$ 1,510,484	-$ 268,767	$ 1,909	-$ 1,777,342	$ 7,257,568
47	1850	Line Transformers	$ 7,835,745	$ 1,409,176	$ 18,691	$ 9,263,612	-$ 1,023,103	-$ 240,391	$ 9,289	-$ 1,254,205	$ 8,009,406
47	1855	Services (Overhead & Underground)	$ 5,421,145	$ 580,972	-$ 515	$ 6,001,602	-$ 641,748	-$ 148,578	$ -	-$ 790,325	$ 5,211,277
47	1860	Meters	$ 3,103,296	$ 299,278	-$ 11,305	$ 3,391,269	-$ 1,222,266	-$ 253,186	$ 106,660	-$ 1,368,792	$ 2,022,477
47	1860	Meters (Smart Meters)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
N/A	1905	Land	$ 1,015,496	$ -	$ -	$ 1,015,496	$ -	$ -	$ -	$ -	$ 1,015,496
47	1908	Buildings & Fixtures	$ 12,744,591	$ 69,709	$ -	$ 12,814,300	-$ 1,251,008	-$ 284,378	$ -	-$ 1,535,386	$ 11,278,914
13	1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (5 years)	$ 276,224	$ 5,438	$ -	$ 281,663	-$ 133,089	-$ 25,789	$ -	-$ 158,878	$ 122,785
10	1920	Computer Equipment - Hardware	$ 703,321	$ 90,162	-$ 7,899	$ 785,584	-$ 517,253	-$ 88,702	$ 6,321	-$ 599,635	$ 185,949
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
50	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	1930	Transportation Equipment	$ 1,008,837	$ 18,630	$ -	$ 1,027,467	-$ 547,190	-$ 81,144	$ 0	-$ 628,334	$ 399,133
8	1935	Stores Equipment	$ 135,334	$ -	$ -	$ 135,334	-$ 67,250	-$ 12,976	$ -	-$ 80,226	$ 55,108
8	1940	Tools, Shop & Garage Equipment	$ 401,120	$ 17,941	$ -	$ 419,061	-$ 262,821	-$ 37,556	$ -	-$ 300,378	$ 118,683
8	1945	Measurement & Testing Equipment	$ 68,740	$ -	$ -	$ 68,740	-$ 31,278	-$ 6,606	$ -	-$ 37,885	$ 30,856
8	1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communications Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1960	Miscellaneous Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1980	System Supervisor Equipment	$ 2,694,887	$ 238,750	$ -	$ 2,933,637	-$ 979,656	-$ 186,508	$ -	-$ 1,166,164	$ 1,767,473
47	1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1995	Contributions & Grants	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	2440	Deferred Revenue[5]	-$ 22,380,208	-$ 8,545,158	$ 45,102	-$ 30,880,264	$ 2,359,320	$ 742,274	-$ 28,754	$ 3,072,840	-$ 27,807,424
	2005	Property Under Finance Lease[7]	$ 170,612	$ 227,479	$ -	$ 398,091	-$ 20,931	-$ 97,053	$ -	-$ 117,984	$ 280,107
		Sub-Total	**$ 66,997,886**	**$ 4,714,066**	**-$ 13,192**	**$ 71,698,760**	**-$ 11,519,242**	**-$ 2,378,298**	**$ 144,013**	**-$ 13,753,526**	**$ 57,945,234**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)	-$ 2,406,055	$ -	$ -	-$ 2,406,055	$ 216,965	$ 48,822	$ -	$ 265,786	-$ 2,140,268
		Total PP&E for Rate Base Purposes	**$ 64,591,832**	**$ 4,714,066**	**-$ 13,192**	**$ 69,292,705**	**-$ 11,302,277**	**-$ 2,329,476**	**$ 144,013**	**-$ 13,487,740**	**$ 55,804,965**
		Construction Work In Progress	$ 3,736,916	$ 1,383,609	$ -	$ 5,120,525				$ -	$ 5,120,525
		Total PP&E	**$ 68,328,748**	**$ 6,097,675**	**-$ 13,192**	**$ 74,413,230**	**-$ 11,302,277**	**-$ 2,329,476**	**$ 144,013**	**-$ 13,487,740**	**$ 60,925,490**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$ 2,329,476**			

			Less: *Fully Allocated Depreciation*	
10		Transportation	Transportation	-$ 178,197
8		Stores Equipment	Stores Equipment	
47		Deferred Revenue	Deferred Revenue	$ 742,274
			Net Depreciation	**-$ 2,893,552**

Accounting Standard	MIFRS
Year	**2021**

			Cost				**Accumulated Depreciation**				
CCA Class [2]	**OEB Account [3]**	**Description [3]**	**Opening Balance [8]**	**Additions [4]**	**Disposals [6]**	**Closing Balance**	**Opening Balance [8]**	**Additions**	**Disposals [6]**	**Closing Balance**	**Net Book Value**
	1609	Capital Contributions Paid	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
12	1611	Computer Software (Formally known as Account 1925)	$ 1,307,075	$ 152,645	$ -	$ 1,459,720	-$ 1,022,234	-$ 171,775	$ -	-$ 1,194,009	$ 265,711
CEC	1612	Land Rights (Formally known as Account 1906)	$ 397,396	$ -	$ -	$ 397,396	-$ 91,462	-$ 12,758	$ -	-$ 104,219	$ 293,177
N/A	1805	Land	$ 1,049,593	$ -	$ -	$ 1,049,593	$ -	$ -	$ -	$ -	$ 1,049,593
47	1808	Buildings	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ 12,615,481	$ 2,419,931	$ -	$ 15,035,412	-$ 1,530,348	-$ 470,450	$ -	-$ 2,000,799	$ 13,034,613
47	1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 18,166,075	$ 4,034,416	-$ 7,542	$ 22,192,949	-$ 1,975,095	-$ 480,144	$ 1,831	-$ 2,453,408	$ 19,739,541
47	1835	Overhead Conductors & Devices	$ 17,472,773	$ 3,114,575	-$ 306,019	$ 20,281,330	-$ 1,734,484	-$ 369,357	$ 41,000	-$ 2,062,841	$ 18,218,490
47	1840	Underground Conduit	$ 3,999,862	$ 577,679	$ -	$ 4,577,541	-$ 657,209	-$ 128,046	$ -	-$ 785,255	$ 3,792,286
47	1845	Underground Conductors & Devices	$ 9,034,911	$ 724,359	-$ 3,821	$ 9,755,448	-$ 1,777,342	-$ 282,177	$ 1,166	-$ 2,058,354	$ 7,697,094
47	1850	Line Transformers	$ 9,263,612	$ 1,293,633	-$ 46,280	$ 10,510,964	-$ 1,254,205	-$ 272,574	$ 23,085	-$ 1,503,694	$ 9,007,270
47	1855	Services (Overhead & Underground)	$ 6,001,602	$ 743,587	-$ 44,932	$ 6,700,257	-$ 790,325	-$ 163,074	$ 8,793	-$ 944,607	$ 5,755,650
47	1860	Meters	$ 3,391,269	$ 231,866	-$ 22,879	$ 3,600,256	-$ 1,368,792	-$ 267,711	$ 10,794	-$ 1,625,710	$ 1,974,547
47	1860	Meters (Smart Meters)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
N/A	1905	Land	$ 1,015,496	$ -	$ -	$ 1,015,496	$ -	$ -	$ -	$ -	$ 1,015,496
47	1908	Buildings & Fixtures	$ 12,814,300	$ 43,734	$ -	$ 12,858,034	-$ 1,535,386	-$ 284,735	$ -	-$ 1,820,120	$ 11,037,914
13	1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (5 years)	$ 281,663	$ 23,353	$ -	$ 305,015	-$ 158,878	-$ 25,317	$ -	-$ 184,195	$ 120,820
10	1920	Computer Equipment - Hardware	$ 785,584	$ 24,956	$ -	$ 810,540	-$ 599,635	-$ 74,712	$ -	-$ 674,347	$ 136,193
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
50	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	1930	Transportation Equipment	$ 1,027,467	$ 668,543	$ -	$ 1,696,010	-$ 628,334	-$ 146,011	$ -	-$ 774,345	$ 921,665
8	1935	Stores Equipment	$ 135,334	$ -	$ -	$ 135,334	-$ 80,226	-$ 12,720	$ -	-$ 92,946	$ 42,389
8	1940	Tools, Shop & Garage Equipment	$ 419,061	$ 74,701	$ -	$ 493,762	-$ 300,378	-$ 26,045	$ -	-$ 326,423	$ 167,339
8	1945	Measurement & Testing Equipment	$ 68,740	$ 2,290	$ -	$ 71,030	-$ 37,885	-$ 6,205	$ -	-$ 44,090	$ 26,940
8	1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communications Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1960	Miscellaneous Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1980	System Supervisor Equipment	$ 2,933,637	$ 251,848	$ -	$ 3,185,485	-$ 1,166,164	-$ 201,020	$ -	-$ 1,367,185	$ 1,818,300
47	1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1995	Contributions & Grants	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	2440	Deferred Revenue[5]	-$ 30,880,264	-$ 7,381,961	$ 14,421	-$ 38,247,803	$ 3,072,840	$ 926,727	-$ 715	$ 3,998,853	-$ 34,248,951
	2005	Property Under Finance Lease[7]	$ 398,091	$ 65,451	-$ 227,479	$ 236,063	-$ 117,984	- 53,900	72,405	-$ 99,479	$ 136,584
		Sub-Total	**$ 71,698,760**	**$ 7,065,604**	**-$ 644,531**	**$ 78,119,834**	**-$ 13,753,526**	**-$ 2,522,004**	**$ 158,359**	**-$ 16,117,172**	**$ 62,002,662**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)	-$ 2,406,055	$ -	$ -	-$ 2,406,055	$ 265,786	$ 48,822	$ -	$ 314,608	-$ 2,091,447
		Total PP&E for Rate Base Purposes	**$ 69,292,705**	**$ 7,065,604**	**-$ 644,531**	**$ 75,713,779**	**-$ 13,487,740**	**-$ 2,473,182**	**$ 158,359**	**-$ 15,802,563**	**$ 59,911,216**
		Construction Work In Progress	$ 5,120,525	$ -	-$ 1,313,631	$ 3,806,894				$ -	$ 3,806,894
		Total PP&E	**$ 74,413,230**	**$ 7,065,604**	**-$ 1,958,162**	**$ 79,520,673**	**-$ 13,487,740**	**-$ 2,473,182**	**$ 158,359**	**-$ 15,802,563**	**$ 63,718,110**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$ 2,473,182**			

			Less: *Fully Allocated Depreciation*	
10		Transportation	Transportation	-$ 199,911
8		Stores Equipment	Stores Equipment	
47		Deferred Revenue	Deferred Revenue	$ 926,727
			Net Depreciation	**-$ 3,199,999**

Accounting Standard	MIFRS
Year	**2022**

			Cost				Accumulated Depreciation				
CCA Class [2]	**OEB Account [3]**	**Description [3]**	**Opening Balance [8]**	**Additions [4]**	**Disposals [6]**	**Closing Balance**	**Opening Balance [8]**	**Additions**	**Disposals [6]**	**Closing Balance**	**Net Book Value**
	1609	Capital Contributions Paid	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
12	1611	Computer Software (Formally known as Account 1925)	$ 1,459,720	$ 321,121	$ -	$ 1,780,841	-$ 1,194,009	-$ 203,750	$ -	-$ 1,397,759	$ 383,082
CEC	1612	Land Rights (Formally known as Account 1906)	$ 397,396	$ -	$ -	$ 397,396	-$ 104,219	-$ 12,758	$ -	-$ 116,977	$ 280,419
N/A	1805	Land	$ 1,049,593	$ -	$ -	$ 1,049,593	$ -	$ -	$ -	$ -	$ 1,049,593
47	1808	Buildings	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ 15,035,412	$ 467,974	$ -	$ 15,503,386	-$ 2,000,799	-$ 516,471	$ -	-$ 2,517,269	$ 12,986,117
47	1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 22,192,949	$ 3,566,867	-$ 12,897	$ 25,746,919	-$ 2,453,408	-$ 558,303	$ 4,845	-$ 3,006,867	$ 22,740,053
47	1835	Overhead Conductors & Devices	$ 20,281,330	$ 1,181,705	-$ 24,496	$ 21,438,539	-$ 2,062,841	-$ 406,986	$ 7,973	-$ 2,461,853	$ 18,976,685
47	1840	Underground Conduit	$ 4,577,541	$ 4,028,775	$ -	$ 8,606,316	-$ 785,255	-$ 185,942	$ -	-$ 971,197	$ 7,635,119
47	1845	Underground Conductors & Devices	$ 9,755,448	$ 1,394,496	-$ 7,161	$ 11,142,784	-$ 2,058,354	-$ 308,457	$ 2,843	-$ 2,363,968	$ 8,778,815
47	1850	Line Transformers	$ 10,510,964	$ 1,001,922	-$ 165,527	$ 11,347,359	-$ 1,503,694	-$ 297,882	$ 20,963	-$ 1,780,613	$ 9,566,745
47	1855	Services (Overhead & Underground)	$ 6,700,257	$ 552,537	$ -	$ 7,252,794	-$ 944,607	-$ 177,470	$ -	-$ 1,122,077	$ 6,130,717
47	1860	Meters	$ 3,600,256	$ 228,496	-$ 40,901	$ 3,787,852	-$ 1,625,710	-$ 276,481	$ 19,422	-$ 1,882,769	$ 1,905,083
47	1860	Meters (Smart Meters)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
N/A	1905	Land	$ 1,015,496	$ -	$ -	$ 1,015,496	$ -	$ -	$ -	$ -	$ 1,015,496
47	1908	Buildings & Fixtures	$ 12,858,034	$ 143,855	$ -	$ 13,001,890	-$ 1,820,120	-$ 286,618	$ -	-$ 2,106,738	$ 10,895,152
13	1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (5 years)	$ 305,015	$ 2,165	$ -	$ 307,180	-$ 184,195	-$ 25,668	$ -	-$ 209,863	$ 97,317
10	1920	Computer Equipment - Hardware	$ 810,540	$ 84,647	$ -	$ 895,187	-$ 674,347	-$ 62,906	$ -	-$ 737,253	$ 157,934
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
50	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	1930	Transportation Equipment	$ 1,696,010	$ 48,945	$ -	$ 1,744,955	-$ 774,345	-$ 221,390	$ 8,242	-$ 987,494	$ 757,462
8	1935	Stores Equipment	$ 135,334	$ -	$ -	$ 135,334	-$ 92,946	-$ 12,410	$ -	-$ 105,356	$ 29,978
8	1940	Tools, Shop & Garage Equipment	$ 493,762	$ 53,427	$ -	$ 547,189	-$ 326,423	-$ 28,879	$ -	-$ 355,302	$ 191,887
8	1945	Measurement & Testing Equipment	$ 71,030	$ 2,425	$ -	$ 73,455	-$ 44,090	-$ 5,608	$ -	-$ 49,698	$ 23,758
8	1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communications Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1960	Miscellaneous Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1980	System Supervisor Equipment	$ 3,185,485	$ 293,063	$ -	$ 3,478,547	-$ 1,367,185	-$ 217,616	$ -	-$ 1,584,800	$ 1,893,747
47	1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1995	Contributions & Grants	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	2440	Deferred Revenue[5]	-$ 38,247,803	-$ 8,996,458	$ 3,302	-$ 47,240,959	$ 3,998,853	$ 1,115,463	-$ 404	$ 5,113,912	-$ 42,127,047
	2005	Property Under Finance Lease[7]	$ 236,063	$ 75,328	-$ 170,612	$ 140,779	-$ 99,479	-$ 41,298	$ 110,185	-$ 30,592	$ 110,187
		Sub-Total	**$ 78,119,834**	**$ 4,451,290**	**-$ 418,291**	**$ 82,152,832**	**-$ 16,117,172**	**-$ 2,731,429**	**$ 174,068**	**-$ 18,674,532**	**$ 63,478,300**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)	-$ 2,406,055	-	-	-$ 2,406,055	$ 314,608	$ 48,822	$ -	$ 363,430	-$ 2,042,625
		Total PP&E for Rate Base Purposes	**$ 75,713,779**	**$ 4,451,290**	**-$ 418,291**	**$ 79,746,778**	**-$ 15,802,563**	**-$ 2,682,607**	**$ 174,068**	**-$ 18,311,102**	**$ 61,435,675**
		Construction Work In Progress	$ 3,806,894	$ 2,201,416	$ -	$ 6,008,309				$ -	$ 6,008,309
		Total PP&E	**$ 79,520,673**	**$ 6,652,705**	**-$ 418,291**	**$ 85,755,087**	**-$ 15,802,563**	**-$ 2,682,607**	**$ 174,068**	**-$ 18,311,102**	**$ 67,443,984**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$ 2,682,607**			

			Less: *Fully Allocated Depreciation*	
10		Transportation	Transportation	-$ 262,688
8		Stores Equipment	Stores Equipment	
47		Deferred Revenue	Deferred Revenue	$ 1,115,463
			Net Depreciation	**-$ 3,535,382**

Accounting Standard MIFRS
Year 2023

			Cost				Accumulated Depreciation				
CCA Class [2]	**OEB Account [3]**	**Description [3]**	**Opening Balance [8]**	**Additions [4]**	**Disposals [6]**	**Closing Balance**	**Opening Balance [8]**	**Additions**	**Disposals [6]**	**Closing Balance**	**Net Book Value**
	1609	Capital Contributions Paid	$ -	$ 4,228,908	$ -	$ 4,228,908	$ -	-$ 84,578	$ -	-$ 84,578	$ 4,144,330
12	1611	Computer Software (Formally known as Account 1925)	$ 1,780,841	$ 166,300	$ -	$ 1,947,141	-$ 1,397,759	-$ 193,111	$ -	-$ 1,590,870	$ 356,271
CEC	1612	Land Rights (Formally known as Account 1906)	$ 397,396	$ -	$ -	$ 397,396	-$ 116,977	-$ 12,758	$ -	-$ 129,735	$ 267,661
N/A	1805	Land	$ 1,049,593	$ -	$ -	$ 1,049,593	$ -	$ -	$ -	$ -	$ 1,049,593
47	1808	Buildings	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ 15,503,386	$ 5,760,943	$ -	$ 21,264,330	-$ 2,517,269	-$ 568,040	$ -	-$ 3,085,310	$ 18,179,020
47	1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 25,746,919	$ 17,890,154	$ -	$ 43,637,074	-$ 3,006,867	-$ 1,042,667	$ -	-$ 4,049,534	$ 39,587,540
47	1835	Overhead Conductors & Devices	$ 21,438,539	$ 1,185,212	$ -	$ 22,623,750	-$ 2,461,853	-$ 408,767	$ -	-$ 2,870,621	$ 19,753,130
47	1840	Underground Conduit	$ 8,606,316	$ 1,840,003	$ -	$ 10,446,319	-$ 971,197	-$ 249,868	$ -	-$ 1,221,065	$ 9,225,254
47	1845	Underground Conductors & Devices	$ 11,142,784	$ 22,145	$ -	$ 11,164,928	-$ 2,363,968	-$ 299,510	$ -	-$ 2,663,478	$ 8,501,450
47	1850	Line Transformers	$ 11,347,359	$ 254,853	$ -	$ 11,602,212	-$ 1,780,613	-$ 296,800	$ -	-$ 2,077,413	$ 9,524,799
47	1855	Services (Overhead & Underground)	$ 7,252,794	$ 270,070	$ -	$ 7,522,864	-$ 1,122,077	-$ 178,655	$ -	-$ 1,300,732	$ 6,222,132
47	1860	Meters	$ 3,787,852	$ 348,369	$ -	$ 4,136,221	-$ 1,882,769	-$ 286,135	$ -	-$ 2,168,904	$ 1,967,317
47	1860	Meters (Smart Meters)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
N/A	1905	Land	$ 1,015,496	$ -	$ -	$ 1,015,496	$ -	$ -	$ -	$ -	$ 1,015,496
47	1908	Buildings & Fixtures	$ 13,001,890	$ 75,000	$ -	$ 13,076,890	-$ 2,106,738	-$ 286,453	$ -	-$ 2,393,191	$ 10,683,699
13	1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (5 years)	$ 307,180	$ -	$ -	$ 307,180	-$ 209,863	-$ 25,677	$ -	-$ 235,540	$ 71,641
10	1920	Computer Equipment - Hardware	$ 895,187	$ 350,000	$ -	$ 1,245,187	-$ 737,253	-$ 119,726	$ -	-$ 856,979	$ 388,208
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
50	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	1930	Transportation Equipment	$ 1,744,955	$ 475,690	$ -	$ 2,220,646	-$ 987,494	-$ 27,467	$ -	-$ 1,014,960	$ 1,205,685
8	1935	Stores Equipment	$ 135,334	$ -	$ -	$ 135,334	-$ 105,356	-$ 12,631	$ -	-$ 117,987	$ 17,347
8	1940	Tools, Shop & Garage Equipment	$ 547,189	$ 78,750	$ -	$ 625,939	-$ 355,302	-$ 32,722	$ -	-$ 388,024	$ 237,915
8	1945	Measurement & Testing Equipment	$ 73,455	$ -	$ -	$ 73,455	-$ 49,698	-$ 5,851	$ -	-$ 55,549	$ 17,906
8	1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communications Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1960	Miscellaneous Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1980	System Supervisor Equipment	$ 3,478,547	$ 230,000	$ -	$ 3,708,547	-$ 1,584,800	-$ 229,816	$ -	-$ 1,814,616	$ 1,893,931
47	1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1995	Contributions & Grants	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	2440	Deferred Revenue[5]	-$ 47,240,959	-$ 24,062,689	$ -	-$ 71,303,648	$ 5,113,912	$ 1,499,071	$ -	$ 6,612,983	-$ 64,690,665
	2005	Property Under Finance Lease[7]	$ 140,779	$ 475,689	$ -	$ 616,468	-$ 30,592	-$ 110,901	-	-$ 141,493	$ 474,975
		Sub-Total	**$ 82,152,832**	**$ 9,589,398**	**$ -**	**$ 91,742,230**	**-$ 18,674,532**	**-$ 2,973,064**	**$ -**	**-$ 21,647,596**	**$ 70,094,634**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)	-$ 2,406,055	-	-	-$ 2,406,055	$ 363,430	$ 48,822	-	$ 412,252	-$ 1,993,803
		Total PP&E for Rate Base Purposes	**$ 79,746,778**	**$ 9,589,398**	**$ -**	**$ 89,336,176**	**-$ 18,311,102**	**-$ 2,924,242**	**$ -**	**-$ 21,235,344**	**$ 68,100,832**
		Construction Work In Progress	$ 6,008,309	$ 2,370,888	-$ 6,008,309	$ 2,370,888				$ -	$ 2,370,888
		Total PP&E	**$ 85,755,087**	**$ 11,960,286**	**-$ 6,008,309**	**$ 91,707,064**	**-$ 18,311,102**	**-$ 2,924,242**	**$ -**	**-$ 21,235,344**	**$ 70,471,720**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$ 2,924,242**			

Less: *Fully Allocated Depreciation*

10		Transportation	Transportation	-$ 110,901
8		Stores Equipment	Stores Equipment	
47		Deferred Revenue	Deferred Revenue	$ 1,499,071
			Net Depreciation	**-$ 4,312,411**

			Accounting Standard	MIFRS							
			Year	2024							
			Cost				Accumulated Depreciation				
CCA Class [2]	OEB Account [3]	Description [3]	Opening Balance [8]	Additions [4]	Disposals [6]	Closing Balance	Opening Balance [8]	Additions	Disposals [6]	Closing Balance	Net Book Value
	1609	Capital Contributions Paid	$ 4,228,908	$ 4,120,000	$ -	$ 8,348,908	-$ 84,578	-$ 251,556	$ -	-$ 336,134	$ 8,012,774
12	1611	Computer Software (Formally known as Account 1925)	$ 1,947,141	$ 325,000	$ -	$ 2,272,141	-$ 1,590,870	-$ 230,200	$ -	-$ 1,821,070	$ 451,071
CEC	1612	Land Rights (Formally known as Account 1906)	$ 397,396	$ -	$ -	$ 397,396	-$ 129,735	-$ 12,758	$ -	-$ 142,493	$ 254,903
N/A	1805	Land	$ 1,049,593	$ -	$ -	$ 1,049,593	$ -	$ -	$ -	$ -	$ 1,049,593
47	1808	Buildings	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -	$ 1,003,404	$ -	$ 1,003,404	$ -	-$ 12,543	$ -	-$ 12,543	$ 990,861
47	1820	Distribution Station Equipment <50 kV	$ 21,264,330	$ 3,175,326	$ -	$ 24,439,656	-$ 3,085,310	-$ 563,694	$ -	-$ 3,649,004	$ 20,790,652
47	1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 43,637,074	$ 33,490,622	$ -	$ 77,127,696	-$ 4,049,534	-$ 1,469,852	$ -	-$ 5,519,385	$ 71,608,310
47	1835	Overhead Conductors & Devices	$ 22,623,750	$ 423,723	$ -	$ 23,047,473	-$ 2,870,621	-$ 417,368	$ -	-$ 3,287,989	$ 19,759,485
47	1840	Underground Conduit	$ 10,446,319	$ 3,500	$ -	$ 10,449,819	-$ 1,221,065	-$ 251,808	$ -	-$ 1,472,873	$ 8,976,946
47	1845	Underground Conductors & Devices	$ 11,164,928	$ 120,525	$ -	$ 11,285,453	-$ 2,663,478	-$ 300,339	$ -	-$ 2,963,817	$ 8,321,637
47	1850	Line Transformers	$ 11,602,212	$ 242,625	$ -	$ 11,844,837	-$ 2,077,413	-$ 299,966	$ -	-$ 2,377,379	$ 9,467,458
47	1855	Services (Overhead & Underground)	$ 7,522,864	$ 2,872,748	$ -	$ 10,395,612	-$ 1,300,732	-$ 199,613	$ -	-$ 1,500,345	$ 8,895,267
47	1860	Meters	$ 4,136,221	$ 694,500	$ -	$ 4,830,721	-$ 2,168,904	-$ 292,503	$ -	-$ 2,461,407	$ 2,369,314
47	1860	Meters (Smart Meters)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
N/A	1905	Land	$ 1,015,496	$ -	$ -	$ 1,015,496	$ -	$ -	$ -	$ -	$ 1,015,496
47	1908	Buildings & Fixtures	$ 13,076,890	$ 75,000	$ -	$ 13,151,890	-$ 2,393,191	-$ 287,286	$ -	-$ 2,680,477	$ 10,471,413
13	1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (5 years)	$ 307,180	$ -	$ -	$ 307,180	-$ 235,540	-$ 25,677	$ -	-$ 261,216	$ 45,964
10	1920	Computer Equipment - Hardware	$ 1,245,187	$ 194,303	$ -	$ 1,439,490	-$ 856,979	-$ 164,375	$ -	-$ 1,021,354	$ 418,136
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
50	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	1930	Transportation Equipment	$ 2,220,646	$ 470,000	$ -	$ 2,690,646	-$ 1,014,960	-$ 74,727	$ -	-$ 1,089,688	$ 1,600,958
8	1935	Stores Equipment	$ 135,334	$ -	$ -	$ 135,334	-$ 117,987	-$ 12,631	$ -	-$ 130,619	$ 4,716
8	1940	Tools, Shop & Garage Equipment	$ 625,939	$ 82,688	$ -	$ 708,627	-$ 388,024	-$ 36,766	$ -	-$ 424,790	$ 283,836
8	1945	Measurement & Testing Equipment	$ 73,455	$ -	$ -	$ 73,455	-$ 55,549	-$ 5,851	$ -	-$ 61,400	$ 12,055
8	1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communications Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1960	Miscellaneous Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1980	System Supervisor Equipment	$ 3,708,547	$ 35,000	$ -	$ 3,743,547	-$ 1,814,616	-$ 236,186	$ -	-$ 2,050,802	$ 1,692,746
47	1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1995	Contributions & Grants	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	2440	Deferred Revenue[5]	-$ 71,303,648	-$ 37,243,234	$ -	-$ 108,546,882	$ 6,612,983	$ 2,416,218	$ -	$ 9,029,201	-$ 99,517,681
	2005	Property Under Finance Lease[7]	$ 616,468	$ -	-$ 65,451	$ 551,017	-$ 141,493	-$ 110,901	$ -	-$ 252,395	$ 298,622
		Sub-Total	**$ 91,742,230**	**$ 10,085,730**	**-$ 65,451**	**$ 101,762,509**	**-$ 21,647,596**	**-$ 2,840,382**	**$ -**	**-$ 24,487,978**	**$ 77,274,531**
		Less Socialized Renewable Energy Generation Investments (input as negative)		$ -	$ -	$ -		$ -	$ -	$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)	-$ 2,406,055	$ -	$ -	-$ 2,406,055	$ 412,252	$ 48,822	$ -	$ 461,074	-$ 1,944,981
		Total PP&E for Rate Base Purposes	**$ 89,336,176**	**$ 10,085,730**	**-$ 65,451**	**$ 99,356,454**	**-$ 21,235,344**	**-$ 2,791,560**	**$ -**	**-$ 24,026,904**	**$ 75,329,550**
		Construction Work In Progress	$ 2,370,888	$ 6,423,739	-$ 1,020,730	$ 7,773,897				$ -	$ 7,773,897
		Total PP&E	**$ 91,707,064**	**$ 16,509,469**	**-$ 1,086,181**	**$ 107,130,351**	**-$ 21,235,344**	**-$ 2,791,560**	**$ -**	**-$ 24,026,904**	**$ 83,103,447**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$ 2,791,560**			

			Less: *Fully Allocated Depreciation*	
10		Transportation	Transportation	-$ 110,901
8		Stores Equipment	Stores Equipment	
47		Deferred Revenue	Deferred Revenue	$ 2,416,218
			Net Depreciation	**-$ 5,096,877**

Appendix D – Bill Impacts Settlement

Ontario Energy Board

Tariff Schedule and Bill Impacts Model
(2023 Cost of Service Filers)

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	1.0604	1.081	750		CONSUMPTION	
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	kwh	RPP	1.0604	1.081	2,000		CONSUMPTION	
GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION	kw	Non-RPP (Other)	1.0604	1.081	25,000	100	DEMAND	
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	kwh	RPP	1.0604	1.081	68		CONSUMPTION	1
SENTINEL LIGHTING SERVICE CLASSIFICATION	kw	Non-RPP (Other)	1.0604	1.081	150	1	DEMAND	1
STREET LIGHTING SERVICE CLASSIFICATION	kw	Non-RPP (Other)	1.0604	1.081	66,376	189	DEMAND	4,334
RESIDENTIAL SERVICE CLASSIFICATION	kwh	Non-RPP (Retailer)	1.0604	1.081	750		CONSUMPTION	
EMBEDDED DISTRIBUTOR	kw	Non-RPP (Other)	1.0604	1.081	77,966	196	DEMAND	
Add additional scenarios if required								
Add additional scenarios if required								
Add additional scenarios if required								
Add additional scenarios if required								
Add additional scenarios if required								
Add additional scenarios if required								
Add additional scenarios if required								
Add additional scenarios if required								
Add additional scenarios if required								
Add additional scenarios if required								
Add additional scenarios if required								
Add additional scenarios if required								

Table 2

RATE CLASSES / CATEGORIES *(eg: Residential TOU, Residential Retailer)*	**Units**	**Sub-Total**						**Total**	
		A		**B**		**C**		**Total Bill**	
		$	**%**	**$**	**%**	**$**	**%**	**$**	**%**
RESIDENTIAL SERVICE CLASSIFICATION - RPP	kwh	$ -	0.0%	$ (0.78)	-1.4%	$ 3.08	4.7%	$ 3.20	2.3%
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION - RPP	kwh	$ (2.65)	-3.9%	$ (4.71)	-4.4%	$ 4.70	3.5%	$ 4.98	1.5%
GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION - Non-RPP (Other)	kw	$ 47.51	6.6%	$ (58.40)	-4.5%	$ 147.41	7.9%	$ 227.50	4.3%
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION - RPP	kwh	$ (2.43)	-15.2%	$ (2.17)	-12.6%	$ (1.85)	-10.2%	$ (1.87)	-7.3%
SENTINEL LIGHTING SERVICE CLASSIFICATION - Non-RPP (Other)	kw	$ (29.09)	-34.7%	$ (27.33)	-31.1%	$ (25.72)	-27.9%	$ (26.04)	-23.7%
STREET LIGHTING SERVICE CLASSIFICATION - Non-RPP (Other)	kw	$ (8,595.46)	-36.1%	$ (8,841.50)	-35.8%	$ (8,606.05)	-33.9%	$ (9,563.07)	-25.8%
RESIDENTIAL SERVICE CLASSIFICATION - Non-RPP (Retailer)	kwh	$ -	0.0%	$ (1.40)	-2.5%	$ 2.47	3.7%	$ 2.58	1.7%
EMBEDDED DISTRIBUTOR - Non-RPP (Other)	kw	$ (55.75)	-4.7%	$ (273.53)	-11.6%	$ 79.79	2.3%	$ 296.29	2.1%

Customer Class:	RESIDENTIAL SERVICE CLASSIFICATION
RPP / Non-RPP:	RPP
Consumption	750 kWh
Demand	- kW
Current Loss Factor	1.0604
Proposed/Approved Loss Factor	1.0810

	Current OEB-Approved			Proposed			Impact		
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change	
Monthly Service Charge	$ 48.13	1	$ 48.13	$ 45.85	1	$ 45.85	$ (2.28)	-4.74%	
Distribution Volumetric Rate	$ -	750	$ -	$ -	750	$ -	$ -		
DRP Adjustment		750	$ (8.64)		750	$ (6.36)	$ 2.28	-26.38%	
Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -		
Volumetric Rate Riders	$ -	750	$ -	$ -	750	$ -	$ -		
Sub-Total A (excluding pass through)			**$ 39.49**			**$ 39.49**	**$ -**	**0.00%**	
Line Losses on Cost of Power	$ 0.0926	45	$ 4.20	$ 0.0926	61	$ 5.63	$ 1.43	34.11%	
Total Deferral/Variance Account Rate Riders	$ 0.0114	750	$ 8.55	$ 0.0114	750	$ 8.57	$ 0.02	0.24%	
CBR Class B Rate Riders	$ (0.0001)	750	$ (0.08)	$ (0.0001)	750	$ (0.09)	$ (0.02)	23.36%	
GA Rate Riders	$ -	750	$ -	$ -	750	$ -	$ -		
Low Voltage Service Charge	$ 0.0025	750	$ 1.88	$ 0.0040	750	$ 2.97	$ 1.09	58.28%	
Smart Meter Entity Charge (if applicable)	$ 0.42	1	$ 0.42	$ 0.42	1	$ 0.42	$ -	0.00%	
Additional Fixed Rate Riders	$ -	1	$ -	$ (3.31)	1	$ (3.31)	$ (3.31)		
Additional Volumetric Rate Riders		750	$ -	$ -	750	$ -	$ -		
Sub-Total B - Distribution (includes Sub-Total A)			**$ 54.46**			**$ 53.68**	**$ (0.78)**	**-1.43%**	
RTSR - Network	$ 0.0083	795	$ 6.60	$ 0.0101	811	$ 8.19	$ 1.59	24.04%	In the manager's summary, discuss the reasoning for the change in RTSR rates
RTSR - Connection and/or Line and Transformation Connection	$ 0.0051	795	$ 4.06	$ 0.0078	811	$ 6.33	$ 2.27	56.06%	In the manager's summary, discuss the reasoning for the change in RTSR rates
Sub-Total C - Delivery (including Sub-Total B)			**$ 65.11**			**$ 68.19**	**$ 3.08**	**4.73%**	
Wholesale Market Service Charge (WMSC)	$ 0.0045	795	$ 3.58	$ 0.0045	811	$ 3.65	$ 0.07	1.94%	
Rural and Remote Rate Protection (RRRP)	$ 0.0007	795	$ 0.56	$ 0.0007	811	$ 0.57	$ 0.01	1.94%	
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%	
TOU - Off Peak	$ 0.0740	473	$ 34.97	$ 0.0740	473	$ 34.97	$ -	0.00%	
TOU - Mid Peak	$ 0.1020	135	$ 13.77	$ 0.1020	135	$ 13.77	$ -	0.00%	
TOU - On Peak	$ 0.1510	143	$ 21.52	$ 0.1510	143	$ 21.52	$ -	0.00%	
Total Bill on TOU (before Taxes)			**$ 139.75**			**$ 142.91**	**$ 3.16**	**2.26%**	
HST	13%		$ 18.17	13%		$ 18.58	$ 0.41	2.26%	
Ontario Electricity Rebate	11.7%		$ (16.35)	11.7%		$ (16.72)	$ (0.37)		
Total Bill on TOU			**$ 141.57**			**$ 144.77**	**$ 3.20**	**2.26%**	

Customer Class:	GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION
RPP / Non-RPP:	RPP
Consumption	2,000 kWh
Demand	- kW
Current Loss Factor	1.0604
Proposed/Approved Loss Factor	1.0810

	Current OEB-Approved			Proposed			Impact		
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change	
Monthly Service Charge	$ 46.24	1	$ 46.24	$ 46.24	1	$ 46.24	$ -	0.00%	
Distribution Volumetric Rate	$ 0.0112	2000	$ 22.40	$ 0.0099	2000	$ 19.75	$ (2.65)	-11.82%	
Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -		
Volumetric Rate Riders	$ -	2000	$ -	$ -	2000	$ -	$ -		
Sub-Total A (excluding pass through)			**$ 68.64**			**$ 65.99**	**$ (2.65)**	**-3.86%**	
Line Losses on Cost of Power	$ 0.0926	121	$ 11.19	$ 0.0926	162	$ 15.00	$ 3.82	34.11%	
Total Deferral/Variance Account Rate Riders	$ 0.0115	2,000	$ 23.00	$ 0.0073	2,000	$ 14.54	$ (8.46)	-36.77%	
CBR Class B Rate Riders	$ (0.0001)	2,000	$ (0.20)	$ (0.0001)	2,000	$ (0.25)	$ (0.05)	23.36%	
GA Rate Riders	$ -	2,000	$ -	$ -	2,000	$ -	$ -		
Low Voltage Service Charge	$ 0.0024	2,000	$ 4.80	$ 0.0036	2,000	$ 7.29	$ 2.49	51.94%	
Smart Meter Entity Charge (if applicable)	$ 0.42	1	$ 0.42	$ 0.42	1	$ 0.42	$ -	0.00%	
Additional Fixed Rate Riders	$ -	1	$ -	$ 0.1327	1	$ 0.13	$ 0.13		
Additional Volumetric Rate Riders		2,000	$ -	$ -	2,000	$ -	$ -		
Sub-Total B - Distribution (includes Sub-Total A)			**$ 107.85**			**$ 103.14**	**$ (4.71)**	**-4.37%**	
RTSR - Network	$ 0.0075	2,121	$ 15.91	$ 0.0091	2,162	$ 19.73	$ 3.82	24.04%	In the manager's summary, discuss the reasoning for the change in RTSR rates
RTSR - Connection and/or Line and Transformation Connection	$ 0.0047	2,121	$ 9.97	$ 0.0072	2,162	$ 15.56	$ 5.59	56.06%	In the manager's summary, discuss the reasoning for the change in RTSR rates
Sub-Total C - Delivery (including Sub-Total B)			**$ 133.72**			**$ 138.43**	**$ 4.70**	**3.52%**	
Wholesale Market Service Charge (WMSC)	$ 0.0045	2,121	$ 9.54	$ 0.0045	2,162	$ 9.73	$ 0.19	1.94%	
Rural and Remote Rate Protection (RRRP)	$ 0.0007	2,121	$ 1.48	$ 0.0007	2,162	$ 1.51	$ 0.03	1.94%	
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%	
TOU - Off Peak	$ 0.0740	1,260	$ 93.24	$ 0.0740	1,260	$ 93.24	$ -	0.00%	
TOU - Mid Peak	$ 0.1020	360	$ 36.72	$ 0.1020	360	$ 36.72	$ -	0.00%	
TOU - On Peak	$ 0.1510	380	$ 57.38	$ 0.1510	380	$ 57.38	$ -	0.00%	
Total Bill on TOU (before Taxes)			**$ 332.34**			$ 337.26	**$ 4.92**	**1.48%**	
HST	13%		$ 43.20	13%		$ 43.84	$ 0.64	1.48%	
Ontario Electricity Rebate	11.7%		$ (38.88)	11.7%		$ (39.46)	$ (0.58)		
Total Bill on TOU			**$ 336.66**			**$ 341.64**	**$ 4.98**	**1.48%**	

Customer Class:	**GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION**
RPP / Non-RPP:	**Non-RPP (Other)**
Consumption	**25,000 kWh**
Demand	**100 kW**
Current Loss Factor	**1.0604**
Proposed/Approved Loss Factor	**1.0810**

	Current OEB-Approved			Proposed			Impact		
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change	
Monthly Service Charge	$ 236.52	1	$ 236.52	$ 236.52	1	$ 236.52	$ -	0.00%	
Distribution Volumetric Rate	$ 4.7930	100	$ 479.30	$ 5.2681	100	$ 526.81	$ 47.51	9.91%	
Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -		
Volumetric Rate Riders	$ -	100	$ -	$ -	100	$ -	$ -		
Sub-Total A (excluding pass through)			**$ 715.82**			**$ 763.33**	**$ 47.51**	**6.64%**	
Line Losses on Cost of Power	$ -	-	$ -	$ -	-	$ -	$ -		
Total Deferral/Variance Account Rate Riders	$ 4.2152	100	$ 421.52	$ 2.7981	100	$ 279.81	$ (141.71)	-33.62%	
CBR Class B Rate Riders	$ (0.0418)	100	$ (4.18)	$ (0.0392)	100	$ (3.92)	$ 0.26	-6.13%	
GA Rate Riders	$ 0.0014	25,000	$ 35.00	$ 0.0004	25,000	$ 8.83	$ (26.17)	-74.76%	
Low Voltage Service Charge	$ 1.3285	100	$ 132.85	$ 1.9424	100	$ 194.24	$ 61.39	46.21%	
Smart Meter Entity Charge (if applicable)	$ -	1	$ -	$ -	1	$ -	$ -		
Additional Fixed Rate Riders	$ -	1	$ -	$ 0.3274	1	$ 0.33	$ 0.33		
Additional Volumetric Rate Riders		100	$ -	$ -	100	$ -	$ -		
Sub-Total B - Distribution (includes Sub-Total A)			**$ 1,301.01**			**$ 1,242.61**	**$ (58.40)**	**-4.49%**	
RTSR - Network	$ 2.9509	100	$ 295.09	$ 3.5905	100	$ 359.05	$ 63.96	21.68%	In the manager's summary, discuss the reasoning for the change in RTSR rates
RTSR - Connection and/or Line and Transformation Connection	$ 2.6717	100	$ 267.17	$ 4.0901	100	$ 409.01	$ 141.84	53.09%	In the manager's summary, discuss the reasoning for the change in RTSR rates
Sub-Total C - Delivery (including Sub-Total B)			**$ 1,863.27**			**$ 2,010.68**	**$ 147.41**	**7.91%**	
Wholesale Market Service Charge (WMSC)	$ 0.0045	26,510	$ 119.30	$ 0.0045	27,025	$ 121.61	$ 2.32	1.94%	
Rural and Remote Rate Protection (RRRP)	$ 0.0007	26,510	$ 18.56	$ 0.0007	27,025	$ 18.92	$ 0.36	1.94%	
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%	
Average IESO Wholesale Market Price	$ 0.0995	26,510	$ 2,637.75	$ 0.0995	27,025	$ 2,688.99	$ 51.24	1.94%	
Total Bill on Average IESO Wholesale Market Price			**$ 4,639.12**			**$ 4,840.44**	**$ 201.33**	**4.34%**	
HST	13%		$ 603.09	13%		$ 629.26	$ 26.17	4.34%	
Ontario Electricity Rebate	11.7%		$ -	11.7%		$ -			
Total Bill on Average IESO Wholesale Market Price			**$ 5,242.20**			**$ 5,469.70**	**$ 227.50**	**4.34%**	

Customer Class:	UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION
RPP / Non-RPP:	RPP
Consumption	68 kWh
Demand	- kW
Current Loss Factor	1.0604
Proposed/Approved Loss Factor	1.0810

	Current OEB-Approved			Proposed			Impact		
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change	
Monthly Service Charge	$ 14.31	1	$ 14.31	$ 12.13	1	$ 12.13	$ (2.18)	-15.22%	
Distribution Volumetric Rate	$ 0.0241	68	$ 1.64	$ 0.0204	68	$ 1.39	$ (0.25)	-15.22%	
Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -		
Volumetric Rate Riders	$ -	68	$ -	$ -	68	$ -	$ -		
Sub-Total A (excluding pass through)			**$ 15.95**			**$ 13.52**	**$ (2.43)**	**-15.22%**	
Line Losses on Cost of Power	$ 0.0926	4	$ 0.38	$ 0.0926	6	$ 0.51	$ 0.13	34.11%	
Total Deferral/Variance Account Rate Riders	$ 0.0115	68	$ 0.78	$ 0.0074	68	$ 0.50	$ (0.28)	-36.07%	
CBR Class B Rate Riders	$ (0.0001)	68	$ (0.01)	$ (0.0001)	68	$ (0.01)	$ (0.00)	23.36%	
GA Rate Riders	$ -	68	$ -	$ -	68	$ -	$ -		
Low Voltage Service Charge	$ 0.0024	68	$ 0.16	$ 0.0036	68	$ 0.25	$ 0.08	51.94%	
Smart Meter Entity Charge (if applicable)	$ -	1	$ -	$ -	1	$ -	$ -		
Additional Fixed Rate Riders	$ -	1	$ -	$ 0.3274	1	$ 0.33	$ 0.33		
Additional Volumetric Rate Riders		68	$ -	$ -	68	$ -	$ -		
Sub-Total B - Distribution (includes Sub-Total A)			**$ 17.27**			**$ 15.10**	**$ (2.17)**	**-12.56%**	
RTSR - Network	$ 0.0075	72	$ 0.54	$ 0.0091	74	$ 0.67	$ 0.13	24.04%	In the manager's summary, discuss the reasoning for the change in RTSR rates
RTSR - Connection and/or Line and Transformation Connection	$ 0.0047	72	$ 0.34	$ 0.0072	74	$ 0.53	$ 0.19	56.06%	In the manager's summary, discuss the reasoning for the change in RTSR rates
Sub-Total C - Delivery (including Sub-Total B)			**$ 18.15**			**$ 16.30**	**$ (1.85)**	**-10.19%**	
Wholesale Market Service Charge (WMSC)	$ 0.0045	72	$ 0.32	$ 0.0045	74	$ 0.33	$ 0.01	1.94%	
Rural and Remote Rate Protection (RRRP)	$ 0.0007	72	$ 0.05	$ 0.0007	74	$ 0.05	$ 0.00	1.94%	
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%	
TOU - Off Peak	$ 0.0740	43	$ 3.17	$ 0.0740	43	$ 3.17	$ -	0.00%	
TOU - Mid Peak	$ 0.1020	12	$ 1.25	$ 0.1020	12	$ 1.25	$ -	0.00%	
TOU - On Peak	$ 0.1510	13	$ 1.95	$ 0.1510	13	$ 1.95	$ -	0.00%	
Total Bill on TOU (before Taxes)			**$ 25.14**			**$ 23.30**	**$ (1.84)**	**-7.33%**	
HST	13%		$ 3.27	13%		$ 3.03	$ (0.24)	-7.33%	
Ontario Electricity Rebate	11.7%		$ (2.94)	11.7%		$ (2.73)	$ 0.22		
Total Bill on TOU			**$ 25.47**			**$ 23.60**	**$ (1.87)**	**-7.33%**	

Customer Class:	**SENTINEL LIGHTING SERVICE CLASSIFICATION**
RPP / Non-RPP:	**Non-RPP (Other)**
Consumption	**150 kWh**
Demand	**1 kW**
Current Loss Factor	**1.0604**
Proposed/Approved Loss Factor	**1.0810**

	Current OEB-Approved			**Proposed**			**Impact**		
	Rate ($)	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**	
Monthly Service Charge	$ 15.08	1	$ 15.08	$ 9.85	1	$ 9.85	$ (5.23)	-34.71%	
Distribution Volumetric Rate	$ 68.7371	1	$ 68.74	$ 44.8815	1	$ 44.88	$ (23.86)	-34.71%	
Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -		
Volumetric Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -		
Sub-Total A (excluding pass through)			**$ 83.82**			**$ 54.73**	**$ (29.09)**	**-34.71%**	
Line Losses on Cost of Power	$ 0.0995	9	$ 0.90	$ 0.0995	12	$ 1.21	$ 0.31	34.11%	
Total Deferral/Variance Account Rate Riders	$ 2.0646	1	$ 2.06	$ 2.6574	1	$ 2.66	$ 0.59	28.71%	
CBR Class B Rate Riders	$ (0.0435)	1	$ (0.04)	$ (0.0446)	1	$ (0.04)	$ (0.00)	2.51%	
GA Rate Riders	$ 0.0007	150	$ 0.11	$ 0.0004	150	$ 0.05	$ (0.05)	-49.52%	
Low Voltage Service Charge	$ 1.0383	1	$ 1.04	$ 1.6200	1	$ 1.62	$ 0.58	56.03%	
Smart Meter Entity Charge (if applicable)	$ -	1	$ -	$ -	1	$ -	$ -		
Additional Fixed Rate Riders	$ -	1	$ -	$ 0.3274	1	$ 0.33	$ 0.33		
Additional Volumetric Rate Riders		1	$ -	$ -	1	$ -	$ -		
Sub-Total B - Distribution (includes Sub-Total A)			**$ 87.88**			**$ 60.55**	**$ (27.33)**	**-31.10%**	
RTSR - Network	$ 2.3093	1	$ 2.31	$ 2.8099	1	$ 2.81	$ 0.50	21.68%	In the manager's summary, discuss the reasoning for the change in RTSR rates
RTSR - Connection and/or Line and Transformation Connection	$ 2.0880	1	$ 2.09	$ 3.1965	1	$ 3.20	$ 1.11	53.09%	In the manager's summary, discuss the reasoning for the change in RTSR rates
Sub-Total C - Delivery (including Sub-Total B)			**$ 92.28**			**$ 66.56**	**$ (25.72)**	**-27.88%**	
Wholesale Market Service Charge (WMSC)	$ 0.0045	159	$ 0.72	$ 0.0045	162	$ 0.73	$ 0.01	1.94%	
Rural and Remote Rate Protection (RRRP)	$ 0.0007	159	$ 0.11	$ 0.0007	162	$ 0.11	$ 0.00	1.94%	
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%	
Average IESO Wholesale Market Price	$ 0.0995	150	$ 14.93	$ 0.0995	150	$ 14.93	$ -	0.00%	
Total Bill on Average IESO Wholesale Market Price			**$ 108.28**			**$ 82.57**	**$ (25.71)**	**-23.74%**	
HST	13%		$ 14.08	13%		$ 10.73	$ (3.34)	-23.74%	
Ontario Electricity Rebate	11.7%		$ (12.67)	11.7%		$ (9.66)			
Total Bill on Average IESO Wholesale Market Price			**$ 109.69**			**$ 83.65**	**$ (26.04)**	**-23.74%**	

Customer Class:	STREET LIGHTING SERVICE CLASSIFICATION
RPP / Non-RPP:	Non-RPP (Other)
Consumption	66,376 kWh
Demand	189 kW
Current Loss Factor	1.0604
Proposed/Approved Loss Factor	1.0810

	Current OEB-Approved			Proposed			Impact		
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change	
Monthly Service Charge	$ 4.61	3852	$ 17,757.72	$ 2.94	3852	$ 11,339.42	$ (6,418.30)	-36.14%	
Distribution Volumetric Rate	$ 31.8708	189	$ 6,023.58	$ 20.3515	189	$ 3,846.43	$ (2,177.15)	-36.14%	
Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -		
Volumetric Rate Riders	$ -	189	$ -	$ -	189	$ -	$ -		
Sub-Total A (excluding pass through)			**$ 23,781.30**			**$ 15,185.84**	**$ (8,595.46)**	**-36.14%**	
Line Losses on Cost of Power	$ -	-	$ -	$ -	-	$ -	$ -		
Total Deferral/Variance Account Rate Riders	$ 3.7874	189	$ 715.82	$ 2.4618	189	$ 465.28	$ (250.54)	-35.00%	
CBR Class B Rate Riders	$ (0.0386)	189	$ (7.30)	$ (0.0413)	189	$ (7.81)	$ (0.51)	7.02%	
GA Rate Riders	$ 0.0014	66,376	$ 92.93	$ 0.0004	66,376	$ 23.45	$ (69.47)	-74.76%	
Low Voltage Service Charge	$ 0.7003	189	$ 132.36	$ 1.0927	189	$ 206.52	$ 74.16	56.03%	
Smart Meter Entity Charge (if applicable)	$ -	1	$ -	$ -	1	$ -	$ -		
Additional Fixed Rate Riders	$ -	1	$ -	$ 0.3274	1	$ 0.33	$ 0.33		
Additional Volumetric Rate Riders		189	$ -	$ -	189	$ -	$ -		
Sub-Total B - Distribution (includes Sub-Total A)			**$ 24,715.11**			**$ 15,873.61**	**$ (8,841.50)**	**-35.77%**	
RTSR - Network	$ 2.2978	189	$ 434.28	$ 2.7959	189	$ 528.42	$ 94.14	21.68%	In the manager's summary, discuss the reasoning for the change in RTSR rates
RTSR - Connection and/or Line and Transformation Connection	$ 1.4083	189	$ 266.17	$ 2.1560	189	$ 407.48	$ 141.31	53.09%	In the manager's summary, discuss the reasoning for the change in RTSR rates
Sub-Total C - Delivery (including Sub-Total B)			**$ 25,415.56**			**$ 16,809.51**	**$ (8,606.05)**	**-33.86%**	
Wholesale Market Service Charge (WMSC)	$ 0.0045	70,385	$ 316.73	$ 0.0045	71,752	$ 322.88	$ 6.15	1.94%	
Rural and Remote Rate Protection (RRRP)	$ 0.0007	70,385	$ 49.27	$ 0.0007	71,752	$ 50.23	$ 0.96	1.94%	
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%	
Average IESO Wholesale Market Price	$ 0.0995	70,385	$ 7,003.27	$ 0.0995	71,752	$ 7,139.32	$ 136.05	1.94%	
Total Bill on Average IESO Wholesale Market Price			**$ 32,785.08**			**$ 24,322.19**	**$ (8,462.89)**	**-25.81%**	
HST	13%		$ 4,262.06	13%		$ 3,161.88	$ (1,100.18)	-25.81%	
Ontario Electricity Rebate	11.7%		$ -	11.7%		$ -			
Total Bill on Average IESO Wholesale Market Price			**$ 37,047.14**			**$ 27,484.07**	**$ (9,563.07)**	**-25.81%**	

Customer Class:	**RESIDENTIAL SERVICE CLASSIFICATION**
RPP / Non-RPP:	**Non-RPP (Retailer)**
Consumption	**750 kWh**
Demand	**- kW**
Current Loss Factor	**1.0604**
Proposed/Approved Loss Factor	**1.0810**

	Current OEB-Approved			Proposed			Impact		
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change	
Monthly Service Charge	$ 48.13	1	$ 48.13	$ 45.85	1	$ 45.85	$ (2.28)	-4.74%	
Distribution Volumetric Rate	$ -	750	$ -	$ -	750	$ -	$ -		
DRP Adjustment		750	$ (8.64)		750	$ (6.36)	$ 2.28	-26.38%	
Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -		
Volumetric Rate Riders	$ -	750	$ -	$ -	750	$ -	$ -		
Sub-Total A (excluding pass through)			**$ 39.49**			**$ 39.49**	**$ -**	**0.00%**	
Line Losses on Cost of Power	$ 0.1036	45	$ 4.69	$ 0.1036	61	$ 6.29	$ 1.60	34.11%	
Total Deferral/Variance Account Rate Riders	$ 0.0114	750	$ 8.55	$ 0.0114	750	$ 8.57	$ 0.02	0.24%	
CBR Class B Rate Riders	$ (0.0001)	750	$ (0.08)	$ (0.0001)	750	$ (0.09)	$ (0.02)	23.36%	
GA Rate Riders	$ 0.0014	750	$ 1.05	$ 0.0004	750	$ 0.26	$ (0.79)	-74.76%	
Low Voltage Service Charge	$ 0.0025	750	$ 1.88	$ 0.0040	750	$ 2.97	$ 1.09	58.28%	
Smart Meter Entity Charge (if applicable)	$ 0.42	1	$ 0.42	$ 0.42	1	$ 0.42	$ -	0.00%	
Additional Fixed Rate Riders	$ -	1	$ -	$ (3.31)	1	$ (3.31)	$ (3.31)		
Additional Volumetric Rate Riders		750	$ -	$ -	750	$ -	$ -		
Sub-Total B - Distribution (includes Sub-Total A)			**$ 56.00**			**$ 54.61**	**$ (1.40)**	**-2.49%**	
RTSR - Network	$ 0.0083	795	$ 6.60	$ 0.0101	811	$ 8.19	$ 1.59	24.04%	In the manager's summary, discuss the reasoning for the change in RTSR rates
RTSR - Connection and/or Line and Transformation Connection	$ 0.0051	795	$ 4.06	$ 0.0078	811	$ 6.33	$ 2.27	56.06%	In the manager's summary, discuss the reasoning for the change in RTSR rates
Sub-Total C - Delivery (including Sub-Total B)			**$ 66.66**			**$ 69.13**	**$ 2.47**	**3.70%**	
Wholesale Market Service Charge (WMSC)	$ 0.0045	795	$ 3.58	$ 0.0045	811	$ 3.65	$ 0.07	1.94%	
Rural and Remote Rate Protection (RRRP)	$ 0.0007	795	$ 0.56	$ 0.0007	811	$ 0.57	$ 0.01	1.94%	
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			**$ 148.50**			**$ 151.04**	**$ 2.55**	**1.71%**	
HST	13%		$ 19.30	13%		$ 19.64	$ 0.33	1.71%	
Ontario Electricity Rebate	11.7%		$ (17.37)	11.7%		$ (17.67)			
Total Bill on Non-RPP Avg. Price			**$ 150.43**			**$ 153.01**	**$ 2.58**	**1.71%**	

Customer Class:	EMBEDDED DISTRIBUTOR
RPP / Non-RPP:	Non-RPP (Other)
Consumption	77,966 kWh
Demand	196 kW
Current Loss Factor	1.0498
Proposed/Approved Loss Factor	1.0713

	Current OEB-Approved			Proposed			Impact		
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change	
Monthly Service Charge	$ 236.52	1	$ 236.52	$ 225.32	1	$ 225.32	$ (11.20)	-4.74%	
Distribution Volumetric Rate	$ 4.7930	196.25	$ 940.63	$ 4.5660	196.25	$ 896.08	$ (44.55)	-4.74%	
Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -		
Volumetric Rate Riders	$ -	196.25	$ -	$ -	196.25	$ -	$ -		
Sub-Total A (excluding pass through)	$ -		$ 1,177.15			$ 1,121.40	$ (55.75)	-4.74%	
Line Losses on Cost of Power	$ -	-	$ -	$ -	-	$ -	$ -		
Total Deferral/Variance Account Rate Riders	$ 4.2152	196	$ 827.23	$ 2.9129	196	$ 571.65	$ (255.58)	-30.90%	
CBR Class B Rate Riders	$ (0.0418)	196	$ (8.20)	$ (0.0489)	196	$ (9.59)	$ (1.39)	16.93%	
GA Rate Riders	$ 0.0014	77,966	$ 109.15	$ 0.0004	77,966	$ 27.55	$ (81.60)	-74.76%	
Low Voltage Service Charge	$ 1.3285	196	$ 260.72	$ 1.9424	196	$ 381.19	$ 120.47	46.21%	
Smart Meter Entity Charge (if applicable)	$ -	1	$ -	$ -	1	$ -	$ -		
Additional Fixed Rate Riders	$ -	1	$ -	$ 0.3274	1	$ 0.33	$ 0.33		
Additional Volumetric Rate Riders	$ -	196	$ -	$ -	196	$ -	$ -		
Sub-Total B - Distribution (includes Sub-Total A)	0		$ 2,366.05			$ 2,092.51	$ (273.53)	-11.56%	
RTSR - Network	$ 2.9509	196	$ 579.11	$ 3.5905	196	$ 704.64	$ 125.53	21.68%	In the manager's summary, discuss the reasoning for the change in RTSR rates
RTSR - Connection and/or Line and Transformation Connection	$ 2.6717	196	$ 524.32	$ 3.8324	196	$ 752.12	$ 227.80	43.45%	In the manager's summary, discuss the reasoning for the change in RTSR rates
Sub-Total C - Delivery (including Sub-Total B)	0		$ 3,469.48			$ 3,549.27	$ 79.79	2.30%	
Wholesale Market Service Charge (WMSC)	$ 0.0045	81,848	$ 368.32	$ 0.0045	83,525	$ 375.86	$ 7.54	2.05%	
Rural and Remote Rate Protection (RRRP)	$ 0.0007	81,848	$ 57.29	$ 0.0007	83,525	$ 58.47	$ 1.17	2.05%	
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%	
Average IESO Wholesale Market Price	$ 0.1036	81,848	$ 8,479.47	$ 0.1036	83,525	$ 8,653.16	$ 173.69	2.05%	
	$ -								
Total Bill on Average IESO Wholesale Market Price	0%		$ 12,374.81			$ 12,637.01	$ 262.20	2.12%	
HST	13%		$ 1,608.73	13%		$ 1,642.81	$ 34.09	2.12%	
Ontario Electricity Rebate	11.7%		$ -	11.7%		$ -			
Total Bill on Average IESO Wholesale Market Price			$ 13,983.53			$ 14,279.82	$ 296.29	2.12%	

Appendix E – Draft Tariff of Rates and Charges

InnPower Corporation
TARIFF OF RATES AND CHARGES
Effective and Implementation Date
This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

RESIDENTIAL SERVICE CLASSIFICATION

This classification refers to the supply of electrical energy to residential customers residing in detached, semi detached, townhouse (freehold or condominium) dwelling units, duplexes or triplexes. Supply will be limited up to a maximum of 200 amp @ 240/120 volt. 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	$	45.85
Rate Rider for Disposition of Deferral/Variance Accounts - effective until December 31, 2024	$	(3.31)
Smart Metering Entity Charge - effective until December 31, 2022	$	0.42
Low Voltage Service Rate	$/kWh	0.0040
Rate Rider for Disposition of Global Adjustment Account (2024) - effective until December 31, 2024 Applicable only for Non-RPP Customers	$/kWh	0.0004
Rate Rider for Disposition of Deferral/Variance Accounts (2024) - effective until December 31, 2024	$/kWh	0.0114
Rate Rider for Disposition of Capacity Based Recovery Account (2024) - effective until December 31, 2024 Applicable only for Class B Customers	$/kWh	(0.0001)
Retail Transmission Rate - Network Service Rate	$/kWh	0.0101
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0078

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

InnPower Corporation
TARIFF OF RATES AND CHARGES
Effective and Implementation Date
This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION

This classification refers to a non-residential account taking electricity at 750 volts or less whose monthly peak demand is less than or expected to be less than 50 kW. 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	$	46.24
Smart Metering Entity Charge - effective until December 31, 2022	$	0.42
Distribution Volumetric Rate	$/kWh	0.0099
Low Voltage Service Rate	$/kWh	0.0036
Rate Rider for Disposition of Global Adjustment Account (2024) - effective until December 31, 2024 Applicable only for Non-RPP Customers	$/kWh	0.0004
Rate Rider for Disposition of Deferral/Variance Accounts (2024) - effective until December 31, 2024	$/kWh	0.0116
Rate Rider for Disposition of Capacity Based Recovery Account (2024) - effective until December 31, 2024 Applicable only for Class B Customers	$/kWh	(0.0001)
Rate Rider for Disposition of Deferral/Variance Accounts - effective until December 31, 2024	$/kWh	(0.0044)
Rate Rider for Disposition of Deferral/Variance Accounts - effective until December 31, 2024	$	0.1327
Retail Transmission Rate - Network Service Rate	$/kWh	0.0091
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0072

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

InnPower Corporation
TARIFF OF RATES AND CHARGES
Effective and Implementation Date
This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

GENERAL SERVICE 50 TO 4,999 KW SERVICE CLASSIFICATION

This classification refers to a non-residential account whose monthly average peak demand is equal to or greater than, or expected to be equal to or greater than 50 kW but less than 5,000 kW. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

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

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

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

If included in the following listing of monthly rates and charges, the rate rider for the disposition of WMS - Sub-account CBR Class B is not applicable to wholesale market participants (WMP), customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new Class B customers.
If included in the following listing of monthly rates and charges, the rate rider for the disposition of Global Adjustment is only applicable to non-RPP Class B customers. It is not applicable to WMP, customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new non-RPP Class B customers.
It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	236.52
Distribution Volumetric Rate	$/kW	5.2681
Low Voltage Service Rate	$/kW	1.9424
Rate Rider for Disposition of Global Adjustment Account (2024) - effective until December 31, 2024 Applicable only for Non-RPP Customers	$/kWh	0.0004
Rate Rider for Disposition of Deferral/Variance Accounts (2024) - effective until December 31, 2024	$/kW	4.4556
Rate Rider for Disposition of Capacity Based Recovery Account (2024) - effective until December 31, 2024 Applicable only for Class B Customers	$/kW	(0.0392)
Rate Rider for Disposition of Deferral/Variance Accounts - effective until December 31, 2024	$/kW	(1.6576)
Rate Rider for Disposition of Deferral/Variance Accounts - effective until December 31, 2024	$	0.3274
Retail Transmission Rate - Network Service Rate	$/kW	3.5905
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	4.0901
Retail Transmission Rate - Network Service Rate - Interval Metered	$/kW	3.5905
Retail Transmission Rate - Line and Transformation Connection Service Rate - Interval Metered	$/kW	3.8324

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

InnPower Corporation
TARIFF OF RATES AND CHARGES
Effective and Implementation Date
This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EMBEDDED DISTRIBUTOR SERVICE CLASSIFICATION

This classification applies to an electricity distributor licensed by the Ontario Energy Board that is provided electricity by means of this distributor's facilities. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

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

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

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

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

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	225.32
Distribution Volumetric Rate	$/kW	4.5660
Low Voltage Service Rate	$/kW	1.9424
Rate Rider for Disposition of Global Adjustment Account (2024) - effective until December 31, 2024. Applicable only for Non-RPP Customers	$/kWh	0.0004
Rate Rider for Disposition of Deferral/Variance Accounts (2024) - effective until December 31, 2024	$/kW	4.6385
Rate Rider for Disposition of Capacity Based Recovery Account (2024) - effective until December 31, 2024 Applicable only for Class B Customers	$/kW	(0.0489)
Rate Rider for Disposition of Deferral/Variance Accounts - effective until December 31, 2024	$/kW	(1.7256)
Rate Rider for Disposition of Deferral/Variance Accounts - effective until December 31, 2024	$	0.3274
Retail Transmission Rate - Network Service Rate	$/kW	3.5905
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	3.8324

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

InnPower Corporation

TARIFF OF RATES AND CHARGES

Effective and Implementation Date

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

UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

This classification refers to a non-residential account taking electricity at 240/120 or 120 volts whose monthly peak demand is less than, or expected to be less than, 50kW and the consumption is unmetered. A detailed calculation of the load will be calculated for billing purposes. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

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

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

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

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

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per connection)	$	12.13
Distribution Volumetric Rate	$/kWh	0.0204
Low Voltage Service Rate	$/kWh	0.0036
Rate Rider for Disposition of Global Adjustment Account (2024) - effective until December 31, 2024 Applicable only for Non-RPP Customers	$/kWh	0.0004
Rate Rider for Disposition of Deferral/Variance Accounts (2024) - effective until December 31, 2024	$/kWh	0.0117
Rate Rider for Disposition of Capacity Based Recovery Account (2024) - effective until December 31, 2024 Applicable only for Class B Customers	$/kWh	(0.0001)
Rate Rider for Disposition of Deferral/Variance Accounts - effective until December 31, 2024	$/kWh	(0.0044)
Rate Rider for Disposition of Deferral/Variance Accounts - effective until December 31, 2024	$	0.3274
Retail Transmission Rate - Network Service Rate	$/kWh	0.0091
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0072

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

InnPower Corporation
TARIFF OF RATES AND CHARGES
Effective and Implementation Date
This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

SENTINEL LIGHTING SERVICE CLASSIFICATION

This classification refers to accounts that are an unmetered lighting load supplied to a sentinel light. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

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

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

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

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

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per connection)	$	9.85
Distribution Volumetric Rate	$/kW	44.8815
Low Voltage Service Rate	$/kW	1.6200
Rate Rider for Disposition of Global Adjustment Account (2024) - effective until December 31, 2024 Applicable only for Non-RPP Customers	$/kWh	0.0004
Rate Rider for Disposition of Deferral/Variance Accounts (2024) - effective until December 31, 2024	$/kW	4.2316
Rate Rider for Disposition of Capacity Based Recovery Account (2024) - effective until December 31, 2024 Applicable only for Class B Customers	$/kW	(0.0446)
Rate Rider for Disposition of Deferral/Variance Accounts - effective until December 31, 2024	$/kW	(1.5743)
Rate Rider for Disposition of Deferral/Variance Accounts - effective until December 31, 2024	$	0.3274
Retail Transmission Rate - Network Service Rate	$/kW	2.8099
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	3.1965

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

InnPower Corporation
TARIFF OF RATES AND CHARGES
Effective and Implementation Date
This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

STREET LIGHTING SERVICE CLASSIFICATION

This classification refers to accounts concerning roadway lighting for a Municipality, Regional Municipality, and/or the Ministry of Transportation. This lighting will be controlled by photocells. The consumption for these customers will be based on the calculated connected load times as established in the approved Ontario Energy Board Street Lighting Load Shape Template. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

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

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

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

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

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per connection)	$	2.94
Distribution Volumetric Rate	$/kW	20.3515
Low Voltage Service Rate	$/kW	1.0927
Rate Rider for Disposition of Global Adjustment Account (2024) - effective until December 31, 2024 Applicable only for Non-RPP Customers	$/kWh	0.0004
Rate Rider for Disposition of Deferral/Variance Accounts (2024) - effective until December 31, 2024	$/kW	3.9202
Rate Rider for Disposition of Capacity Based Recovery Account (2024) - effective until December 31, 2024 Applicable only for Class B Customers	$/kW	(0.0413)
Rate Rider for Disposition of Deferral/Variance Accounts - effective until December 31, 2024	$/kW	(1.4584)
Rate Rider for Disposition of Deferral/Variance Accounts - effective until December 31, 2024	$	0.3274
Retail Transmission Rate - Network Service Rate	$/kW	2.7959
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	2.1560

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

InnPower Corporation
TARIFF OF RATES AND CHARGES
Effective and Implementation Date
This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

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.

APPLICATION

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

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

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

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

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	4.55

ALLOWANCES

Transformer Allowance for Ownership - per kW of billing demand/month	$/kW	(0.60)
Primary Metering Allowance for transformer losses - applied to measured demand and energy	%	(1.00)

InnPower Corporation
TARIFF OF RATES AND CHARGES
Effective and Implementation Date
This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

SPECIFIC SERVICE CHARGES

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

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

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

Customer Administration

Arrears certificate	$	15.00
Easement letter	$	15.00
Credit reference/credit check (plus credit agency costs)	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	30.00
Returned cheque (plus bank charges)	$	15.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	30.00

Non-Payment of Account

Late payment - per month (effective annual rate 19.56% per annum or 0.04896% compounded daily rate)	%	1.50
Reconnection at meter - during regular hours	$	65.00
Reconnection at meter - after regular hours	$	185.00
Reconnection at pole - during regular hours	$	185.00
Reconnection at pole - after regular hours	$	415.00

Customer Initiated

Reconnection at meter - during regular hours	$	65.00
Reconnection at meter - after regular hours	$	185.00
Reconnection at pole - during regular hours	$	185.00
Reconnection at pole - after regular hours	$	415.00

Other

Special meter reads	$	30.00
Temporary service - install & remove - overhead - no transformer	$	632.00
Temporary service - installation and removal - underground - no transformer	$	468.00
Temporary service - installation and removal - overhead - with transformer	$	2,525.00
Specific charge for access to the power poles - per pole/year with the exception of wireless attachments	$	37.78

InnPower Corporation
TARIFF OF RATES AND CHARGES
Effective and Implementation Date
This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

RETAIL SERVICE CHARGES (if applicable)

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

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

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

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

Retail Service Charges refer to services provided by a distributor to retailers or customers related to the supply of competitive electricity.

One-time charge, per retailer, to establish the service agreement between the distributor and the retailer	$	117.02
Monthly Fixed Charge, per retailer	$	46.81
Monthly Variable Charge, per customer, per retailer	$/cust.	1.16
Distributor-consolidated billing monthly charge, per customer, per retailer	$/cust.	0.69
Retailer-consolidated billing monthly credit, per customer, per retailer	$/cust.	(0.69)
Service Transaction Requests (STR)		
Request fee, per request, applied to the requesting party	$	0.59
Processing fee, per request, applied to the requesting party	$	1.16
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)	$	4.68
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)	$	2.34

LOSS FACTORS

If the distributor is not capable of prorating changed loss factors jointly with distribution rates, the revised loss factors will be implemented upon the first subsequent billing for each billing cycle.

Total Loss Factor - Secondary Metered Customer < 5,000 kW	1.0821
Total Loss Factor - Primary Metered Customer < 5,000 kW	1.0713

Appendix F – Pre-Settlement Clarification Questions

2-Staff-74

Reference: **Pole Condition Results**
Ref 1: 2-Staff-13
2: 2-Staff-19

Question:

METSCO has reported the percentage of wood poles in poor and very poor condition to be 21% of the total population in the 2021 asset condition assessment. In InnPower's last Distribution System Plan as part of the EB-2016-0085 proceeding, InnPower reported that 4% of wood poles were in poor and very poor condition (2016 asset condition assessment). InnPower stated in response to 2-Staff-19 that the number of poles in poor condition increased as a result of pole testing and the asset condition assessment. InnPower noted that the testing methodology had not changed from the last Distribution System Plan.

a) Please provide further detail beyond the asset condition assessment results as to why the condition of poles worsened five-fold since 2016.

b) InnPower stated in Staff-13 that pole outages are classified as foreign interference.

i. Please confirm that all pole-related outages are recorded under foreign interference and if not, please explain what other cause codes pole outages are recorded under.

ii. Please provide a breakdown of pole-related outages separate from foreign interference.

Response:

a. In the 2015 poles ACA, there was a substantial number of poles in the fair condition that over the last seven years moved into the poor and very poor condition. As it was stated in Section 4.1.1.3 of the Distribution Asset Condition

Assessment back in 2015 it was observed that the overall pole condition is much better than what would be expected from the age profile. This is mainly due to the fact that a great number of old poles, that have reached more than 45 years of service, received “fair” rating. It should be noted that these poles, constituting over 85% of the fair poles, are expected to significantly deteriorate to poor condition or worse if the corresponding remaining strength drops below 80% or they start to reveal severe damage on the civil structure. Thus, these poles would require more frequent diagnostic testing and possible remedial work or replacement depending on criticality.

b. i. and ii. pole related outages were only recorded under and due to foreign interference. InnPower did not have pole related outages in any other category.

2-Staff-75

Reference: Switchgear Replacements

Ref 1: 2-Staff-23

Question:

According to the METSCO asset condition assessment, no switchgears appear to be in poor condition. InnPower noted in response to 2-Staff-23 that it found multiple switchgears to be inoperable during inspections.

a) When was the inspection last conducted?

i. If the inspection was conducted before the asset condition assessment, why are the inspection results not reflected within the asset condition assessment?

b) Please provide the latest inspection summary report that includes switchgears as well as switches.

Response:

a) The last inspection was conducted in the summer of 2022. Currently, there is an on-going 2023 inspections (as part of InnPower's three-year cycle).

i) The ACA was conducted using 2021 data. The inoperable switchgears were identified in the 2022 switchgear inspection.

b) InnPower does not have summary reports. Switchgears are inspected individually with individual switchgear reports. Switch inspections are carried out using IR scanning, with only hot spots reported.

2-Staff-76

Reference: InnPower TS Project Environmental Assessment

Ref 1: 2-Staff-29

Question:

InnPower confirmed in response to 2-Staff-29 that it will capitalize the environmental assessment for the InnPower TS at the end of the year.

a) Please explain why InnPower has not included the environmental assessment as CWIP until the InnPower TS is in-service.
b) Please confirm whether InnPower has consulted its external auditor regarding the accounting treatment of the capitalization of the environmental assessment for the InnPower TS given its material significance.
    i) If confirmed, please provide a confirmation from the external auditor that they agree with the capitalization accounting treatment.
    ii) If not, please explain why not.

Response:

a) InnPower has modified the schedule to include it in CWIP
b) No. InnPower's auditors are unable to give accounting advice to maintain independence.

2-Staff-77

Reference: 44kV Line Extension from BATU

Ref 1: 2-Staff-38

Question:

InnPower confirmed in response to 2-Staff-38 that the 44kV line extension from BATU will not be in-service prior to December 31, 2023.

Please confirm that InnPower will adjust its 2024 Test Year in-service additions to include the 44kV line extension, while including the line extension in CWIP in the 2023 Bridge Year.

Response:

InnPower confirms that the 44kV line has been included in CWIP for the 2023 Bridge Year and as an in-service addition for the 2024 Test Year.

2-Staff-78

Reference: BATU

Ref 1: InnPower IRRS 2024 CoS, 2-Staff-39

Ref 2: Revised BATU DVA Draft Accounting Order_20230808

Ref 3: Att 2-Staff-39_BATU_Contribution_Revenue_Requirement_20230808

Question:

As stated in Reference 2 that the purpose of the new deferral account, “Batu Installment Account” is to capture the revenue requirement associated with InnPower’s capital contribution installments paid to Hydro One Networks Inc. for InnPower’s proportionate share of the BATU Project, as approved in EB-2018-0117, that are not included in the current rate base.

Reference 2 outlines accounting entries proposed by InnPower as follows.

USoA # Account Description

Dr: 1508 Other Regulatory Assets – Sub-Account BATU Installments Paid

Cr: 1609 Capital Contributions Paid

To record capital contribution installments paid by InnPower to Hydro One relating to the BATU project

Dr: 1508 Other Regulatory Assets – Sub-Account BATU Installments Paid, Carrying Charges

Cr: 1525 Miscellaneous Deferred Debits

To record carrying charges and PILs associated with amounts recorded in Sub-Account BATU

Installments Paid

Dr: 1508 Sub-Account BATU Installment Depreciation Expense

Cr: 1508 Sub-Account BATU Installment Accumulated Depreciation

To record depreciation expense associated with amounts recorded in Sub-Account BATU Installments

Paid

In addition, InnPower provided the 2025 balances in four sub-accounts of the proposed BATU DVA in Reference 1 as shown below.

Sub-Acct BATU Installments Paid $6,180,000

Sub-Acct BATU Installment Depreciation Expense $103,000

Sub-Acct BATU Installment Accumulated Deprec $103,000

Sub-Acct BATU Installment, Carrying Charges $9,457

a) Based on the calculations provided in Reference 3, the accumulative incremental revenue requirements on the capital contribution payments at the end of 2025 show a debit balance of $336,057 before the carrying charges. However, this balance is not included as part of the 2025 balances in the four sub-accounts of the proposed BATU DVA provided in Reference 1.

i. Please confirm whether InnPower intends to record the incremental revenue requirements in a separate sub-account.

ii. If confirmed, please establish a separate sub-account to record the incremental revenue requirements. Additionally, please revise the draft accounting order as necessary.

iii. If not, please elaborate on how the incremental revenue requirements on the capital contribution installments paid will be captured in the proposed new deferral accounts.

b) InnPower has indicated in Reference 2 that the second entry is to record carrying charges and PILs associated with amounts recorded in Sub-Account BATU Installments Paid. Additionally, staff notes that the amounts recorded in Sub-Account BATU Installments Paid are the annual capital contribution installments paid according to the first entry in Reference 2. Carrying charges should be recorded on the incremental revenue requirements calculated on the capital contribution paid, whereas the PILs are part of the incremental revenue requirements.

i. Please establish a new sub-account for the carrying charges on the BATU incremental revenue requirements.

ii. Please revise the draft accounting order accordingly.

c) Please provide the proposed accounting entry to transfer the net book value of the capital contribution paid balance to the rate base upon the disposition in InnPower's next rebasing application.

d) Given the incremental revenue requirements are calculated and set based on the 2025 to 2027 installments, please provide InnPower's view on the disposition of the DVA in the respective IRM applications.

e) Please confirm that InnPower would not seek the additional recovery if Hydro One requires more installment payments than the budgeted amounts in 2025 to 2027.

Response:

a-b) As identified by OEB Staff above, the 2025 balance reported in 2-Staff-39 for Sub-Acct BATU Installment, Carrying Charges was incorrect. If the Sub-Account noted were to capture

Return on Rate Base, PILs, and interest on balances within the various appropriate Sub-Accounts, the 2025 balance would be $243,604, as opposed to the $9,457 previously reported.

The above said, in response to OEB Staff's questions in a) and b) above, InnPower proposes revising the Draft Accounting Order to include an additional Sub-Account, with the effect of separating Return and PILs from interest on BATU account balances. The former will be the subject of a new Sub-Account (Sub-Account BATU Installment Return and PILs), while the latter will continue to be captured in Sub-Account BATU Installment, Carrying Charges.

Based on the above change, please find as Attachment (Att Staff-78_Revised_BATU_DVA_Draft_Accounting_Order_20230818) to this response a revised version of the Draft Account Order. Further, please see below the Debits and Balances for each sub-account over the entire 2024 to 2028 period, including a summary of balances on disposition to Gross PP&E, Accumulated Depreciation, and Recovery from Ratepayers. Finally, please find as Attachment (Att Staff-78_BATU_Contribution_RR_with_Sub-Accounts_20230818) to this response an expanded version of the DVA Approach tab of the Attachment to 2-Staff-39, in which the calculated incremental revenue requirement and other amounts have been allocated to the Sub-Accounts listed below.

BATU Installment Sub-Accounts	2024	2025	2026	2027	2028
BATU Installments Paid					
Debits	$ 2,060,000	$ 4,120,000	$ 4,120,000	$ 4,120,000	$ -
Balance	$ 2,060,000	$ 6,180,000	$10,300,000	$14,420,000	$14,420,000
BATU Installment Depreciation Expense					
Debits	$ 20,600	$ 82,400	$ 164,800	$ 247,200	$ 288,400
Balance	$ 20,600	$ 103,000	$ 267,800	$ 515,000	$ 803,400
BATU Installment Accumulated Depreciation					
Debits	$ 20,600	$ 82,400	$ 164,800	$ 247,200	$ 288,400
Balance	$ 20,600	$ 103,000	$ 267,800	$ 515,000	$ 803,400
BATU Installment Return and PILs					
Debits	$ 23,148	$ 209,909	$ 415,264	$ 614,548	$ 761,464
Balance	$ 23,148	$ 233,057	$ 648,322	$ 1,262,869	$ 2,024,333
BATU Installment Carrying Charges					
Debits	$ 1,089	$ 9,457	$ 31,179	$ 67,080	$ 114,680
Balance	$ 1,089	$ 10,546	$ 41,726	$ 108,806	$ 223,486

On Disposition	
Debit to Gross PP&E	$14,420,000
Debit to Accumulated Depreciation	$ 803,400
Recovery from Ratepayers	$ 3,051,219

c) Please see below the accounting entries that would be required to transfer the net book value of the BATU capital contribution paid balance to rate base as part of InnPower's next rebasing application.

<u>USoA #</u>	<u>Account Description</u>
Dr: 1609	Capital Contributions Paid
Cr: 1508	Other Regulatory Assets – Sub-Account BATU Installments Paid
To transfer the gross value of capital contribution installments paid by InnPower to Hydro One relating to the BATU project from Sub-Account BATU Installments Paid to Capital Contributions Paid	
Dr: 2105	Accum. Amortization of Electric Utility Plant - Property, Plant, & Equipment
Cr: 1508	Other Regulatory Assets – Sub-Account BATU Installment Accumulated Depreciation
To transfer the accumulated depreciation associated with capital contribution installments paid by InnPower to Hydro One relating to the BATU project from Sub-Account BATU Installment Accumulated Depreciation to Accumulated Amortization of Electric Utility Plan – Property, Plan, & Equipment	

d) InnPower has not proposed disposition of the balances in IRM proceedings, rather proposed disposition at the next Cost of Service.

e) Per response to 2-Staff-38 e) " If there are cost increases for the BATU project following InnPower's cost of service application, InnPower will capture the variance between the actual capital contribution and the budgeted capital contribution for 50% of the 2024 contribution and the actual contributions in 2025 through 2027 in the DVA."

3-Staff-79

Reference: Customer Forecast

Ref 1: 3-Staff-40

Question:

InnPower's response refers to a table of new subdivisions. OEB staff cannot find the referenced table.

a) Please provide the table responding to the referenced question.

Response:

The table is provided in pre-settlement question VECC-46.

4-Staff-80

Reference: Overhead Distribution Lines/Feeders

Ref 1: 4-Staff-49

Question:

InnPower stated that the Overhead Distribution Lines/Feeders budget includes station maintenance costs, which have doubled from 2023 to 2024.

a) Please provide the new stations that have been added to InnPower's service territory since 2017, if any.

Response:

a) Below is a list of new stations added to InnPower's service area since 2017:

1. Sandy Cove T2
2. Cedar Point T2
3. Belle Ewart T1
4. Big Bay Point T1 (expanded from 8kV to 27.6kV)

4-Staff-81

Reference: Management, Finance, Administrative, Regulatory, and Information Technology

Ref 1: 4-Staff-53

Ref 2: Chapter 2 Appendices – 2-N

Ref 3: Chapter 2 Appendices – 2-JC

Question:

InnPower showed that in 2024 it contracted $415k in costs to InnServices for Chief Compliance Officer, Corporate Services, Information Technology, health and safety, and legal services at market price.

a) Please provide the business case analysis for contracting out to InnServices as per the Affiliate Relationship Code.
b) Please confirm that InnPower used a fair and competitive bidding process to establish the market price.
c) Do InnServices costs include any markup to the market price? If so, how much is the markup?
d) Prior to 2021, the budget for Management, Finance, Administrative, Regulatory, and Information Technology was approximately $1.5 million. How did InnPower operate within the budget in 2021?

Response:

a)

Position	**Cost to Contract out to External Services (Includes**	**Comparator Role in MEARIE Salary Survey**

	57% Burdened Rate)	
Chief Compliance Officer	$ 266,240.60	Average of Head of Customer Service & Head of Information Technology
Corporate Services	$230,165.14	Manager, Risk Management
IT Manager - Salary	$192,571.49	Average of Manager, Information Systems and Information Security
IT Analyst (Cyber Security)	$165,044.68	Network Specialist
Manager, Health & Safety	$191,489.76	Health & Safety Manager
Law Clerk	$109,303.40	* No comparator in Mearie Salary Survey. Source: Robert Half Salary Guide
Total Cost:	**$1,154,815.07**	

InnServices provides these positions for approximately $415k. It would cost an additional $739,815 if InnPower were to acquire these positions from the market. These shared services provide a substantial benefit to the ratepayers.

b) InnPower investigated the market for the above noted positions but did not issue a request for proposal for the services. InnPower looked at the comparative salaries, noted above, to provide these services internally as well sharing those services with its affiliate on a proportional basis. As noted above the incremental cost to provide those services internally would represent an incremental cost of approximately $740k, versus the approximate cost of $415k using the shared resources.

c) InnServices charges base labour and burden rate to InnPower. InnServices does not charge a markup to InnPower.

d) The year 2021 was lower since a number of staff left and there were vacancies in positions such as President, a system analyst, a regulatory manager, and a financial analyst. When these positions were re-hired, the new hires began at a lower rate and progressed through the steps in our pay bands.

6-Staff-82

Reference: Depreciation

Ref 1: 6-Staff-62

Ref 2: 2024 Income Tax PILs Workform, August 10, 2023

Ref 3: Chapter 2 Appendix 2-BA, August 10, 2023

Question:

OEB staff notes that the Net Depreciation figures in Reference 3 do not align with the Amortization amounts recorded in Sch 1 in Reference 2 for the historical, bridge, or test years.

The Net Depreciation amounts in Reference 3 have excluded the depreciation amounts of Other Non Rate-Regulated Utility Assets.

It seems that InnPower has double-counted the deduction of the depreciation amounts of Other Non Rate-Regulated Utility Assets by excluding the amounts in the Amortization of Tangible Assets in the PILs model. OEB staff notes that the net depreciation amount in Reference 3 should match with the Amortization of tangible assets amount in Reference 2.

a) Please confirm OEB staff's observation above.
b) If confirmed, please update the applicable schedules.

Response:

a) Correct
b) See below

PILs Tax Provision - Historical Year

Note: Input the actual information from the tax returns for the historical year.

					Wires Only	
Regulatory Taxable Income				H1	$ 759,590	A
Combined Tax Rate and PILs	Ontario Tax Rate (Maximum 11.5%)	11.50%	B			
	Federal tax rate (Maximum 15%)	15.00%	C			
	Combined tax rate (Maximum 26.5%)				26.50%	D = B+C
Total Income Taxes					$ 201,291	E = A * D
Investment Tax Credits						F
Miscellaneous Tax Credits						G
Total Tax Credits					$ -	H = F + G
Corporate PILs/Income Tax Provision for Historical Year					$ 201,291	I = E - H

Adjusted Taxable Income - Historical Year

	T2S1 line #	Total for Legal Entity	Non-Distribution	Historic Wires Only
Income before PILs/Taxes	(A + 101 + 102)	2,703,000		2,703,000
Additions:				
Interest and penalties on taxes	103	612		612
Amortization of tangible assets	104	3,535,382		3,535,382
Loss on disposal of assets	111	61,000		61,000
Charitable donations and gifts from Schedule 2	112	1,250		1,250
Non-deductible meals and entertainment expense	121	2,073		2,073
Reserves from financial statements - balance at the end of the year	126	142,732		142,732
Recapture of SR&ED expenditures	231	18,054		18,054
Customer Deposits (ITA 20(1)(a))	295	7,676,000		7,676,000
Capital Contributions Received (ITA 12(1)(x))		9,002,299		9,002,299
Amortization expensed in Distribution expenses		213,148		213,148
Amortization expensed of Capital Lease		30,000		30,000
Tax component of OCI		11,709		11,709
Total Additions		**20,694,260**	**0**	**20,694,260**
Deductions:				
Capital cost allowance from Schedule 8	403	4,661,942		4,661,942
Reserves from financial statements - balance at beginning of year	414	162,065		162,065
Capital Lease Payments	395	26,000		26,000
	395	7,676,000		7,676,000
ITA 13(7.4) Election - Capital Contributions Received		8,996,458		8,996,458
Deferred Revenue - ITA 20(1)(m) reserve		1,115,205		1,115,205
Total Deductions		**22,637,670**	**0**	**22,637,670**
Net Income for Tax Purposes		**759,590**	**0**	**759,590**
TAXABLE INCOME		**759,590**	**0**	**759,590**

PILS Tax Provision - Bridge Year

	Tax Rate	Small Business Rate (If Applicable)	Taxes Payable	Effective Tax Rate		Reference	Wires Only	
Regulatory Taxable Income						B1	$ 5,673,437	A
Ontario (Max 11.5%)	11.5%	11.5%	$ 652,445	11.5%	B			
Federal (Max 15%)	15.0%	15.0%	$ 851,016	15.0%	C			
Combined effective tax rate (Max 26.5%)							26.50%	D = B + C
Total Income Taxes							$ 1,503,461	E = A * D
Investment Tax Credits								F
Miscellaneous Tax Credits								G
Total Tax Credits							$ -	H = F + G
Corporate PILs/Income Tax Provision for Bridge Year							$ 1,503,461	I = E - H

Adjusted Taxable Income - Bridge Year

	T2S1 line #	Working Paper Reference	Total for Regulated Utility
Income before PILs/Taxes	(A + 101 + 102)		3,558,240

Additions:			
Amortization of tangible assets	104		4,427,210
Non-deductible meals and entertainment expense	121		5,505
Reserves from financial statements- balance at end of year	126	B13	186,918
Customer Deposits (ITA 20(1)(a))	295		7,676,000
Capital Contributions Received (ITA 12(1)(x))			65,088,473
Amortization expensed in Distribution expenses			110,901
Total Additions			**77,495,007**
Deductions:			
Capital cost allowance from Schedule 8	403	B8	5,160,053
Reserves from financial statements - balance at beginning of year	414	B13	142,732
Capital Lease Payments	395		124,909
	395		3,040,000
ITA 13(7.4) Election - Capital Contributions Received			65,088,473
Deferred Revenue - ITA 20(1)(m) reserve			1,823,643
Total Deductions		calculated	**75,379,810**
Net Income for Tax Purposes		calculated	**5,673,437**
TAXABLE INCOME		calculated	**5,673,437**

PILs Tax Provision - Test Year

Wires Only

Regulatory Taxable Income T1 $ 661,957 A

	Tax Rate	Small Business Rate (If Applicable)	Taxes Payable	Effective Tax Rate	
Ontario (Max 11.5%)	11.5%	11.5%	$ 76,125	11.5%	B
Federal (Max 15%)	15.0%	15.0%	$ 99,294	15.0%	C

Combined effective tax rate (Max 26.5%)		26.50%	D = B + C	
Total Income Taxes		$ 175,419	E = A * D	
Investment Tax Credits			F	
Miscellaneous Tax Credits			G	
Total Tax Credits		$ -	H = F + G	
Corporate PILs/Income Tax Provision for Test Year		$ 175,419	I = E - H	S. Summary
Corporate PILs/Income Tax Provision Gross Up [1]	73.50% J = 1-D	$ 63,246	K = I/J-I	
Income Tax (grossed-up)		$ 238,665	L = K + I	S. Summary

Taxable Income - Test Year

	T2 S1 line #	Working Paper Reference	Test Year Taxable Income
Net Income Before Taxes		A.	2,870,840
Additions:			
Amortization of tangible assets *2-4 ADJUSTED ACCOUNTING DATA P489*	104		5,029,700
Non-deductible meals and entertainment expense	121		5,515
Reserves from financial statements- balance at end of year	126	T13	186,918
Customer Deposits (ITA 20(1)(a))	295		3,040,000
Capital Contributions Received (ITA 12(1)(x))			24,260,348
Amortization expensed in Distribution expenses			110,901
Total Additions			**32,633,382**
Deductions:			
Capital cost allowance from Schedule 8	403	T8	4,983,930
Reserves from financial statements - balance at beginning of year	414	T13	186,918
Capital Lease Payments	395		117,136
Customer Deposits (ITA 20(1)(m))	395		3,040,000
ITA 13(7.4) Election - Capital Contributions Received			24,260,348
Deferred Revenue - ITA 20(1)(m) reserve			2,253,932
Total Deductions		calculated	**34,842,264**
NET INCOME FOR TAX PURPOSES		calculated	**661,957**
REGULATORY TAXABLE INCOME		calculated	**661,957**

SEC-1

Reference: 1-SEC-2 (2023 & 2024 Budget), 2-SEC-22a (2017 – 2024 CWIP), 2-Staff-38d (BATU)

Question:

a) In 2-SEC-22, part (a) InnPower has confirmed the CWIP shown in the table. In 2-Staff-35d, InnPower states “Per discussion with Hydro One, the 44kV line extension from BATU will not be in-service prior to December 31, 2023. The capital costs paid to Hydro One for the construction will be in work in process and will be carried over and put in-service in 2024”. In the Budget Update for 2024 (See attachment to 1-SEC-2), InnPower shows $6,424 of the spend in 2024 as TS Expenditures WIP.

   Please reconcile the above three documents and confirm the capital expenditures and in-service additions for 2023 and 2024.

Response:

a) See attached file named ***Att SEC-1_Capital_&_WIP***

SEC-2

Reference: 1-SEC-6

Question:

a) Please confirm that based on the 2022 scorecard provided, the update targets for SAIDI and SAIFI would be 1.76 and .83.

Response:

a) As per OEB staff, “the last set of targets were applicable for 2017 to 2021 scorecards and were based off 2012-2016 data. Since 2021 scorecard marks the completion of 5-year period, the targets were again reset for 2022 scorecard based off 2017-2021 data.”

Please refer to Att SEC-2_InnPower_Reliability_Targets for the OEB’s calculation of InnPower’s reliability targets.

SEC-3

Reference: 2-Staff-4a,b, 2-SEC-18

Question:

a) Please explain the difference in the capital to the end of June 2023 shown in the attachment to 2-Staff-4b ($244k) and that shown in 2-SEC-18 ($4575k).

Response:

a) The capital to the end of June 2023 shown in 2-Staff-4b are in service additions. The capital shown in 2-SEC-18 are in-service additions plus work in process (WIP).

SEC-4

Reference: Appendix 2-AA, 2-Staff-31, 2-VECC-5

Question:

With respect to the fleet costs:

a) Is the cost of leasing the small service truck and a pool of other vehicles in 2023 shown under Fleet or under Miscellaneous.
b) Depending on InnPower's answer for part (a) what is the other $476k in 2023 Miscellaneous capital costs for?
c) Please confirm that the $470k in 2024 is for the new bucket truck in 2024.

Response:

a) The cost of leasing the small service truck and fleet pooled vehicles are reported under Miscellaneous in Appendix 2-AA.
b) The $476k reported in 2023 under Miscellaneous is for the following:
    1. 4 small fleet vehicles ($181,036)
    2. 1 small service truck ($294,653)
c) Correct. The $470k budgeted in 2024 is for the new bucket truck that was ordered in 2021.

SEC-5

Reference: 2-Staff-29d

Question:

a) The interrogatory asked InnPower to confirm if the $1.35 million related to the new TS environmental assessment is recorded as work in progress in 2-BA. Please respond to the interrogatory as posed.

Response:

a) The $1.35 million relating to the new TS environmental assessment is recorded in 2-BA as an in-service addition, not work in progress.

SEC-6

Reference: 3-SEC-26

Question:

a) InnPower's states: "To mitigate this inappropriate outcome, InnPower has adjusted all historical data such that the five transitioning customers are included within the customer count and kWh values across all years within the 10-year historical period (plus the first half of 2023)…. The result of this adjustment is that the average kWh per customer in both the GS 50kW rate classes accurately reflects inclusion of these five customers in GS >50kW." In the updated load forecast attached to 3-SEC-26, the average kWh/customer for the GS > 50 kW class is 719,088 for 2017 to 2022, versus the forecasted 682,783."

   Please produce an update load forecast which does not adjust the historical data for the five transitioning GS < 50 kW customers but includes them in 2023, as is done for a new customer.

Response:

a) Please find attached (Att SEC-6_IPC_Exhibit_3_Load_Forecast_20230817) to this response a version of the load forecast which incorporates the change requested above. InnPower would highlight the following with respect to the outcomes of the scenario requested:
   - Neither the original GS customer adjustment included in InnPower's adopted load forecast issued August 8, 2023, nor this requested scenario, alter the total forecast power purchased or forecast billed kWh in the Test Year. As such, the effect of the scenario requested is a re-allocation of forecast kWh between rate classes, with subsequent implications for forecast Test Year kW.
   - Tab "Rate Class Customer Model" demonstrates the impacts of the requested scenario on forecast customer count by rate class. In the Test Year, the net effect is an increase of one customer to the GS<50kW rate class, and a

decrease of one customer to the GS>50kW rate class. However, the result of not adjusting for the movement of customers from GS<50kW to GS>50kW is an annualized increase in GS>50kW customer count of over 15% for 2023. Given the ten-year average is closer to 3%, and the known reality that the vast majority of customer additions in 2023 were customer migrations and not new customers, this input is not reasonable or appropriate in InnPower's assessment.

- The net effect of this scenario is a decrease to forecast Residential kWh in the Test Year, and increases to forecast kWh in both the GS<50kW and GS>50kW rate classes, with corresponding increases to GS>50kW forecast kW.

SEC-7

Reference: 4-SEC-33; Appendix 2-K

Question:

a) For the purposes of Appendix 2-K, when are the additional positions for 2023 and 2024 assumed to start?

Response:

a) InnPower assumes a start of January 2023 and January 2024 for additional positions in Appendix 2-K.

VECC-46

Reference: 3-Staff-40

Question:

a) With respect to Staff 40 a) are the annual values for "connections added" just the residential connections? If yes, are there any other connections associated with subdivision growth?

b) The table referenced in response to Staff 40 b) appears to be missing. Please provide.

Response:

a) Yes, the annual values for "connections added" are just the residential subdivision connections. There are temporary and streetlight connections that are in addition to the numbers provided.

b) The following is the table of new subdivisions with connections completed or anticipated in 2023 and 2024. For those not yet connected, InnPower does not have detailed information on the stage of construction at this point in the process as it with the developers' consultants and contractors.

Residential Growth Forecast and 2023 Actuals to End Of June 2023-2024					
Development Name	**Developer**	**Unit Type**	**2023**	**End Of June 2023 Energized units**	**2024**
(A) Barrie Lockhart Road GP Inc. (400 Lockhart)	Hewitt	Residential	31	8	11

(B) BEMP Holdings 2 Inc. & Honeyfield Bemp 2 Limited (BEMP II)	Hewitt	Residential	32	34	37
(F) GG (9 Mile) Limited (Lockmaple)	Hewitt	Residential	15	99	45
(G) 620 Lockhart Road	Hewitt	Residential	40		40
(Part of I) Pratt Hansen Group Inc. (Bistro 6)	Hewitt	Residential	34		0
(Part of I) Pratt Hansen Group Inc. (Elements Condo (Bistro 6 West))	Hewitt	Residential	41		51
(I, J, K-1) Pratt Hansen Group/Bradley Homes (Hewitt's Gate Subdivision)	Hewitt	Residential	45	113	39
(M) 1091369 Ontario Inc. (Bulut)	Hewitt	Residential	48		56
(N)(N-1) Sandy Creek Estates (979 & 989 Mapleview Dr E)	Hewitt	Residential	25		
(O,P-1) Ontario Ltd. & Honeyfield Big Bay Point Inc. (BLUE SKY)	Hewitt	Residential	26		26
(Q) 970 Mapleview Inc.	Hewitt	Residential	35	78	59
(AA) Miele development Inc. (Miele)	Hewitt	Residential			11
(Y*) Maple View south (Innisfil) Ltd. (953 Mapleview Drive)	Hewitt	Residential	18		26
(Z) 961 Big Bay Ltd.	Hewitt	Residential	4		
(T) Crown (Barrie) Developments Inc. (1012 Yonge)	Hewitt	Residential			0
(V) ASA Developments Inc. (989 Yonge Street)	Hewitt	Residential			16
W* Ballymore Building (Barrie) Corp.	Hewitt	Residential			43
X Mapleview Friday Corporation (947 Mapleview)	Hewitt	Residential			24
Dipoce (Innisfil) Inc. A* (DiPoce)	Salem	Residential	27		25

Crisdawn Construction Inc. B* (Bear Creek Ridge)	Salem	Residential	9	8	6
Ruby Red Maple Development Inc. H*	Salem	Residential	13		13
H&H Capital (I-1,J-1,K-1)	Salem	Residential	53		45
Waterstand Construction Ltd. (P-1, Q-1, R-1)	Salem	Residential	21		32
2431805 Ontario Inc. & 2528286 Ontario Inc. (910 Veterans) V	Salem	Residential	13		
FridayHarbour	Bigbaypoint	Residential	26		26
Previn Court 2	Alcona	Residential	26		26
Previn Court 2	Alcona	Residential	16		32
Alcona Downs 3 Ph4	Alcona	Residential	8	9	8
Grand Sierra Ph1	Alcona	Residential	26		26
Grand Sierra Ph2	Alcona	Residential	7		5
Alcona Capital	Alcona	Residential	19	10	26
Churchill Downs	Churchill	Residential	8		
Victoria Street Cookstown	Cookstown	Residential	16		12
Innis Village _Phase 2A_[Parkbridge Lifestyle Communities]	Sandy Cove	Residential	11	2	14
Innis Village_Phase 3_[Parkbridge Lifestyle Communities]	Sandy Cove	Residential	18		18
Innis Village_Phase 2B_[Parkbridge Lifestyle Communities]	Sandy Cove	Residential	16		26
Innis Village_Phase 4_[Parkbridge Lifestyle Communities]	Sandy Cove	Residential	13		16
Innis Village_[Parkbridge Lifestyle Communities]_institutional units	Sandy Cove	Condo			53
Sleeping Lion (Phase 3)	Alcona South	Residential	31	140	18

Sleeping Lion (Phase 4)	Alcona South	Residential	11		26
LSAMI P1 Phase 4	Lefroy	Residential	13		13
LSAMI P1 Phase 5	Lefroy	Residential	11	29	9
LSAMI P3 (Ballymore)	Lefroy	Residential	13		14
LSAMI P3	Lefroy	Residential	11		11
Cornerstone Towns-Lefroy	Lefroy	Residential	5		
Brookfield (Rix Home Farms)_[Stroud Village Developers Group]	Stroud	Residential			11
1008 Innisfil Beach Road	Alcona	Condo	15		16
1326 Innisfil Beach Road	Alcona	Condo			26
TOTAL			**819**	**530**	**1026**

VECC-47

Reference: 3-SEC-27 and 3-VECC-10

Question:

a) Please provide the results for load forecast model where the regression equation used to forecast power purchases includes a COVID variable that is equal to 1.0 for the months of March 2020 to March 2022 and zero for all other months.

Response:

a) Please find attached (***Att VECC-47_IPC_Load_Forecast***) a version of the load forecast (as updated during interrogatories to incorporate 2023 YTD actuals) in which a COVID Flag variable has been added to the regression for the period March 2020 through March 2022. The net impact of the variable addition is a decrease to total billed kWh of 1.5%, and a decrease to total billed kW of 1.2% relative to the updated load forecast filed August 8, 2023.

VECC-48

Reference: Updated RRWF, Tab 14 (line 35)
4-Staff-53
Updated Chapter 2 Appendices, Tab 2H

Question:

a) As a result of the interrogatory responses, Miscellaneous Revenues have been reduced by $519,951 due to changes in accounts 4375 and 4380. Please explain more fully the reasons for the changes in the 2024 forecast values for these accounts and provided updated versions of the Table 6-28 and 6-29 from the original application.

Response:

a) The miscellaneous revenues were reduced by $519,951 due to an error in the budgeting software used to forecast the 4375 and 4380 balances. The revenue balance was pre-programmed to add a 15% service fee (which InnPower no longer charges), as well as incorrectly allocating the costs to the shared services account. InnPower has taken measures to correct the error for future forecasting of shared services.

   Please see below for the updated versions of Table 6-28 and Table 6-29 from the original application.

Updated Table 6-28:

Account 4375 - Revenues from Non-Utility Operations

	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2021 Actual	2022 Actual	2023 Bridge Year	2024 Test Year
Reporting Basis	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
OEB Programs (CDM, AFT)	-$ 262,821	-$ 773,482	$ 17,709	-$ 253,936	-$ 92,191	-$ 2,932	$ -	$ -
Revenue from Affiliates	-$ 664,566	-$ 779,124	-$ 1,217,059	-$ 1,297,155	-$ 1,449,409	-$ 899,221	-$ 1,468,277	-$ 1,638,395
Thermal / Gas	$ -	-$ 12,460	-$ 18,536	-$ 18,473	-$ 27,457	-$ 23,612	-$ 28,800	-$ 28,800
Total	-$ 927,387	-$ 1,565,066	-$ 1,217,885	-$ 1,569,564	-$ 1,569,057	-$ 925,764	-$ 1,497,077	-$ 1,667,195

Updated Table 6-29:

Account 4380 - Expenses from Non-Utility Operations

	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2021 Actual	2022 Actual	2023 Bridge Year	2024 Test Year
Reporting Basis	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
OEB Programs (CDM, AFT)	$ 557,043	$ 516,483	$ 239,776	$ 253,936	$ 92,191	$ 2,918	$ -	$ -
Expenses from Affiliates	$ 614,902	$ 673,552	$ 740,312	$ 1,007,560	$ 930,054	$ 889,062	$ 1,351,287	$ 1,512,775
Thermal / Gas	$ -	$ 36,958	$ 5,154	$ 5,126	$ 4,535	$ 1,456	$ 5,467	$ 5,784
Total	$ 1,171,945	$ 1,226,993	$ 985,242	$ 1,266,622	$ 1,026,780	$ 893,437	$ 1,356,754	$ 1,518,559

VECC-49

Reference: 7-VECC-31

Question:

a) Please clarify whether the Embedded Distributor uses any of the InnPower assets in Accounts 1820, 1830, 1835, 1840 or 1845.

Response:

a) Yes, the Embedded Distributor uses the assets in the accounts mentioned above.

Appendix G – BATU DVA Accounting Order

SCHEDULE B

DECISION AND ORDER

ACCOUNTING ORDER – INNPOWER CORPORATION BATU INSTALLMENT DEFERRAL ACCOUNT

INNPOWER CORPORATION

EB-2023-0033

NOVEMBER 23, 2023

InnPower Corporation

Draft Accounting Order

Account 1508 – Other Regulatory Assets, Sub-account BATU Installment Deferral Account

InnPower Corporation (InnPower) shall establish the new deferral account, “BATU Installment Deferral Account”, effective January 1, 2024, to record 50% of the incremental revenue requirement impact associated with five years of capital contribution installments paid to Hydro One Networks Inc. (HONI) in accordance with section 6.3.19 of the *Transmission System Code* for the Barrie Area Transformer Upgrade Project (BATU Project) as accepted by the Ontario Energy Board (OEB) in EB-2018-0117. It is currently estimated that the five years of capital contribution installments paid to HONI will total $20.6 million.

Assuming that the BATU Project is in-service before the end of 2023, this account only concerns the incremental revenue requirement impact related to capital contribution installment payments paid by InnPower for the BATU Project for: (i) half of the 2024 capital contribution installment payments due to the OEB half year rule; and (ii) 2025 to 2027 (Incentive Period Payments). It is currently estimated that the total value of the Incentive Period Payments will total $14,420,000 based on the updated estimates in EB-2018-0117. Installment payments in 2023 and half of the payment in 2024 have been incorporated into InnPower’s rate base in the 2024 Test Year and are currently estimated at $6,180,000. If the BATU Project is delayed and is not in-service until 2024, please see section (4) below.

As part of this settlement, the Parties agree to a modified BATU Installment Deferral Account which would record for later final disposition: (i) 50% of the revenue requirement for the Incentive Period Payments; (ii) 50% of the revenue requirement for actually installment as a result of variances in actual and estimate BATU Project costs; (iii) 100% of the revenue requirement impact of any BATU Project delays; and (iv) differences between the rate rider revenue collected and the approved amount for disposition. For clarity, the Parties in EB-2023-0033 agreed that InnPower’s collection of 50% of the revenue requirement does not indicate the prudence of the capital contribution installments paid to HONI for its proportionate share of the BATU Project, which will be assessed on final disposition.

1. Sub-accounts description

The deferral account will include three sub-accounts, which will be used for disposition.

(a) Account 1508 – Other Regulatory Assets, Sub-Account BATU Installment Revenue Requirement Impact

This account will be used to record 50% of the incremental revenue requirement impact associated with the Incentive Period Payments.

(b) Account 1508 – Other Regulatory Assets, Sub-Account BATU Installments, Rate Rider Revenues

This account will be used to record the collection of revenue through BATU rate riders implemented as part of InnPower's 2026 through 2028 IRM applications, and any riders implemented thereafter to complete collection of balances in the Revenue Requirement Impact and Carrying Charges sub-accounts. The BATU rate riders are further described in Section 3 below.

(c) Account 1508 – Other Regulatory Assets, Sub-Account BATU Installment, Carrying Charges

This will be used to record interest on the sub-accounts Revenue Requirement Impact and Rate Rider Revenues. InnPower will record monthly interest using the prescribed interest rates set by the OEB. Simple interest will be calculated on the opening monthly balances of the accounts until the balances are fully disposed of.

2. Interim disposition of accounts until rebasing

InnPower will seek interim disposition of revenue requirement amounts recorded in accordance with Schedule A as part of InnPower's annual IRM applications at the earliest practical date, which is anticipated to be no earlier than InnPower's 2026 IRM application, and will be brought forward for interim disposition in each IRM thereafter up to InnPower's next Cost of Service application.

3. Final Disposition of the accounts

Final disposition including any true-ups described above will be sought as part of InnPower's next Cost of Service application.

Clearance of these true-up variances will ensure the true-up of Revenue Requirement Impact amounts owed to InnPower (or to ratepayers) relative to Rate Rider Revenues collected on an actual basis, inclusive of Carrying Charges calculated on both sub-account balances.

InnPower's entries in the BATU Installment Deferral Account will adjust for cost variances such that on final disposition as part of InnPower's next rebasing application the revenue requirement recovered from ratepayers is reflective of 50%[1] of the revenue requirement derived from actual capital contribution installments paid.

4. Circumstance where BATU Project delayed to 2024 (or beyond)

Should the in-service date for the BATU project vary from 2023 into 2024 or beyond, InnPower will:

a) make entries in Account 1609 – Capital Contributions Paid and Account 2120 – Accumulated Amortization of Electric Utility Plant – Intangibles which are reflective of the actual costs and timing of the BATU installment payments and their associated accumulated depreciation;
b) reflect that the BATU installment payments currently included in 2024 rate base and rates (which is the 2023 and half of the 2024 BATU installment payments, the “Rate Based Installment Payments”) should, on an actual basis, not collect any revenue requirement for periods when the BATU Project is not in-service;
c) calculate the 2024 through 2028 revenue requirements associated with the Rate Based Installment Payments;
d) make annual credit entries to the Revenue Requirement Impacts Sub-Account which are equal to 100% of such revenue requirement amounts in (c) equal to the period where the BATU Project is not in-service.
e) seek final disposition of the BATU Installment Revenue Requirement Impact account as part of InnPower’s next Cost of Service application equal to the net difference between the credit entries in (d) and 50% of the revenue requirement associated with the actual Incentive Period Payments.

(a) Account 1508 – Other Regulatory Assets, Sub-Account BATU Installment Revenue Requirement Impact

Should the in-service date of the BATU Project be delayed from 2023 into 2024 or beyond, InnPower will make credit entries to the BATU Installment Revenue Requirement Impact sub-account equal to 100% of the revenue requirement associated with BATU installments currently included in the 2024 rate base, which on an actual basis should not have been included due to the delayed in-service date.

[1] With the exception of any credit amount to the benefit of ratepayers resulting from a delay to the in-service date of the BATU Project. Revenue requirement amounts associated with such credits will be recorded at 100%, as opposed to 50%

4. Establishment of deferral account sub-accounts

The deferral account sub-accounts will be established as follows:

1) Account 1508, Other Regulatory Assets – Sub-Account BATU Installment, Revenue Requirement Impact

2) Account 1508, Other Regulatory Assets – Sub-Account Batu Installment, Rate Rider Revenues

3) Account 1508, Other Regulatory Assets – Sub-Account BATU Installment, Carrying Charges

The following outlines the proposed accounting entries:

Dr: 1508	Sub-Account BATU Installment Revenue Requirement Impact
Cr: 4080	Distribution Services Revenue
To record 50% of the incremental revenue requirement impact associated with the Incentive Period Payments.	
Dr: 1508	Sub-Account BATU Installment, Carrying Charges
Cr: 4405+	Interest Income
To record Carrying Charges associated with amounts recorded in Sub-Accounts BATU Installment Revenue Requirement Impact	
Dr: 1100	Customer Accounts Receivable
Cr: 1508	Sub-Account BATU Installment, Rate Rider Revenues
To record the collection of rate rider billings	
Dr: 6035	Other Interest Expense
Cr: 1508	Sub-Account BATU Installments, Carrying Charges
To record carrying charges on the rate riders collected	

Schedule A
BATU Installment Deferral Account

BATU Installment Sub-Accounts

	2024	2025	2026	2027	2028	2029	Forecast Final Disposition
BATU Installment Revenue Requirement Impact							
Debits	$0	$145,359	$288,454	$428,528	$522,235	$0	
Interim Disposition	$0	$0	-$145,359	-$288,454	-$428,528	-$522,235	-$1,384,576
Balance	$0	$145,359	$288,454	$428,528	$522,235	$0	
BATU Installment Carrying Charges							
Debits	$0	$3,619	$10,802	$17,853	$23,674	$13,004	
Interim Disposition	$0	$0	-$3,619	-$10,802	-$17,853	-$36,678	-$68,952
Balance	$0	$3,619	$10,802	$17,853	$23,674	$0	
BATU Installment Rate Rider Revenues							
Credits	$0	$0	$148,979	$299,255	$446,381	$558,912	$1,453,527
Balance	$0	$0	$148,979	$448,234	$894,615	$1,453,527	

Dispostion to Ratepayers	
Sum of Disposition Amounts (Revenue Requirement Impact & Carrying Charge Debits)	-$1,453,527
Sum of Rate Rider Revenues	$1,453,527
Forecast Difference	$0