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

DECISION AND ORDER

EB-2024-0008

ATIKOKAN HYDRO INC.

Application for electricity distribution rates and other charges beginning May 1, 2025

BEFORE: Pankaj Sardana
Presiding Commissioner

March 27, 2025

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

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1 OVERVIEW

This is the Ontario Energy Board's (OEB) Decision and Order on an application filed by Atikokan Hydro Inc. (Atikokan Hydro) seeking approval for changes to the rates Atikokan Hydro charges for electricity distribution effective May 1, 2025.

Atikokan Hydro filed a settlement proposal (Settlement Proposal), dated March 20, 2025, that reflected a comprehensive settlement between Atikokan Hydro, Vulnerable Energy Consumers Coalition (VECC), and OEB staff, collectively the parties, on all issues included on the approved Issues List.[1]

As OEB staff was a party to the settlement, it did not file a separate submission on the Settlement Proposal.

For the reasons described in this Decision and Order, the OEB approves the Settlement Proposal as filed.

As a result of this Decision and Order, it is estimated that a typical residential customer with a monthly consumption of 750 kWh could see a total bill decrease (excluding taxes and the Ontario Electricity Rebate) of approximately $6.87 per month (4.8%).

[1] The Issues List approved in the OEB's Decision on Issues List dated February 4, 2025.

2 CONTEXT AND 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 October 30, 2024, Atikokan Hydro filed a cost of service application with the OEB under section 78 of the *Ontario Energy Board Act, 1998*. The application requested OEB approval of Atikokan Hydro's proposed electricity distribution rates for five years, using the Price Cap Incentive Rate-setting (Price Cap IR) option described in the *Renewed Regulatory Framework for Electricity*. Under the Price Cap IR option, with an approved 2025 Test Year, Atikokan Hydro will be eligible to apply to have its 2026-2029 rates adjusted mechanistically, based on inflation and the OEB's assessment of Atikokan Hydro's efficiency.

The application was accepted by the OEB as complete on November 13, 2024. The OEB issued a Notice of Hearing on November 21, 2024, inviting parties to apply for intervenor status. VECC was granted intervenor status and eligibility for cost awards.

The OEB issued Procedural Order No. 1 on December 16, 2024. This order established, among other things, the timetable for a discovery process and a settlement conference.

This proceeding participated in the OEB's pilot for new adjudicative process for very small utilities (the VSU pilot). This new process included a one-day Issues Meeting, held on January 15, 2025, in order for OEB staff and parties to discuss the application and seek agreement on (i) an Issues List for the application that sets out issues that are relevant to the application; and (ii) an Interrogatory Issues List that sets out issues that require further discovery.

On January 21, 2025, OEB staff filed an Issues List and a list of clarifications, updates and corrections to be made by Atikokan Hydro that had been agreed to by all parties for the OEB's consideration. The OEB approved the proposed Issues List and list of clarifications, updates and corrections on February 4, 2025. Atikokan Hydro responded

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[2] Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach, October 18, 2012

[3] Handbook for Utility Rate Applications, October 13, 2016.

to the list of clarifications, updates and corrections submitted by OEB staff and VECC on February 19, 2025.

A settlement conference was held on February 24-25 and re-convened on March 4, 2025. Atikokan Hydro, VECC, and OEB staff participated in the settlement conference. OEB staff was a party to the settlement. As part of the VSU pilot, the facilitator for the settlement conference was an OEB Commissioner.

Atikokan Hydro filed a Settlement Proposal covering all issues on March 20, 2025. The Settlement Proposal is attached as Schedule A to this Decision and Order.

3 DECISION ON THE SETTLEMENT PROPOSAL

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

Key aspects of the Settlement Proposal are summarized below.

- A reduction to the as-filed base revenue requirement of $1.74M by $96k to $1.64M
- Atikokan Hydro will comply with any orders or directions from the OEB resulting from the Cost of Capital Generic Proceeding that are applicable to Atikokan Hydro. Atikokan also agreed to use the OEB's long-term debt rate instead of the weighted average cost of long-term debt.
- A reduction to the as-filed 2025 net capital in-service additions of $153k (24%), resulting in a 2025 in-service additions budget of $482k.
- An increase of $50k annually to the capital contributions budget from 2025-2029.
- Commitment by Atikokan Hydro to provide at its next Cost of Service application an in-house summary of its assets by asset type and the number of assets in each of its condition ratings based on data available at the time.
- A 2025 Operations, Maintenance & Administration (OM&A) expenditures envelope reduction of $5k, resulting in a 2025 OM&A of $1.34M.
- Commitment by Atikokan Hydro to internally investigate ways to improve or reduce its Activity and Program-Based Benchmarking (APB) OM&A unit costs and report back at its next Cost of Service application on the areas investigated and the results.
- A $1,445 reduction to the as-filed 2025 PILs forecast, reducing it to NIL.
- A $1,522 reduction to Other Revenue.
- An update to the 2025 demand forecast for the Street Lighting rate class from 1,058 kW to 956.52 kW, and an update to the 2025 demand forecast for the General Service > 50 to 4999 kW rate class from 46,637 kW to 44,938 kW.
- Disposition of Group 1 deferral and variance accounts (DVA) over a one-year period, and Group 2 DVAs over a two-year period.
    - Group 1 DVAs credit balance of $36,847
    - Group 2 DVAs credit balance of $228,450

- Atikokan Hydro's new rates will be effective on the same date that Atikokan Hydro is able to implement them, subject to May 1, 2025 being the earliest effective date permitted.

Findings

The OEB has reviewed the Settlement Proposal and finds that it reflects a reasonable outcome that balances the interests of Atikokan Hydro and its customers. Furthermore, the OEB finds that the Settlement Proposal is comprehensive, addressing all issues on the approved Issues List.

The OEB accepts the agreed-upon reductions to Atikokan Hydro's revenue requirement, capital expenditures, and OM&A envelope, as well as the commitments made regarding asset management and benchmarking improvements. These measures are expected to contribute to cost-effectiveness while ensuring continued reliable service. The OEB also finds that the proposed disposition periods for Group 1 and Group 2 deferral and variance accounts are appropriate.

Given the thorough consideration of all issues and the fair outcome for all parties, the OEB approves the Settlement Proposal as filed.

4 IMPLEMENTATION

As part of the Settlement Proposal, the parties agreed that new rates should be effective on the date that they are implemented.

Atikokan Hydro filed tariff sheets and detailed supporting material with the Settlement Proposal, including all relevant calculations showing the impact of the implementation of the Settlement Proposal on its revenue requirement, the allocation of the revenue requirement to its rate classes and the determination of the final rates and rate riders, including bill impacts. These tariff sheets included cost of capital parameters issued by the OEB on October 31, 2024.[4]

Subsequent to the Settlement Proposal filed by Atikokan Hydro, the OEB issued its Decision and Order in the generic Cost of Capital proceeding on March 27, 2025.[5]

The OEB understands that, to implement rates effective May 1, 2025, Atikokan Hydro requires a final rate order by **May 19, 2025**. The OEB is of the view that there is sufficient time to proceed with a draft rate order process that incorporates the final 2025 cost of capital parameters before that date. Unless Atikokan Hydro is not able to update its draft rate order to allow for implementation by **May 1, 2025**, it should file an updated draft rate order, incorporating the final 2025 cost of capital parameters, with detailed supporting material showing the impact of any required adjustments for the OEB's review and approval.

Alternatively, if Atikokan Hydro is not able to update its draft rate order to allow for implementation by **May 1, 2025**, it should advise the OEB of such by **April 1, 2025**, and continue to follow the requirements within the OEB's letter dated **October 31, 2024**, with respect to cost of capital parameter updates.[6] In this case, no further updates to the models or tariff sheets will be required and the OEB will issue a final rate order in April 2025.

VECC is eligible to apply for cost awards in this proceeding. The OEB will make provision for VECC to file its cost claim at a later date.

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[4] EB-2024-0063, OEB Letter, 2025 Cost of Capital Parameters, October 31, 2024
[5] EB-2024-0063, Decision and Order, March 27, 2025
[6] EB-2024-0063, OEB Letter, October 31, 2024

5 ORDER

THE ONTARIO ENERGY BOARD ORDERS THAT:

1. The Settlement Proposal set out in Schedule A is approved.

2. Atikokan Hydro Inc. shall file a letter with the OEB advising as to whether it will be able to update the proposed Tariff of Rates and Charges to reflect the decision in the cost of capital generic proceeding by **April 1, 2025**.

3. If Atikokan Hydro Inc. is able to update the proposed Tariff of Rates and Charges, it shall file with the OEB and forward to VECC a draft rate order with the proposed Tariff of Rates and Charges by **April 7, 2025**. Atikokan Hydro Inc. shall also include customer rate impacts and detailed information in support of the calculation of final rates in the draft rate order.

4. If Atikokan Hydro Inc. updates the proposed Tariff of Rates and Charges, VECC and OEB staff may file any comments on the draft rate order with the OEB by **April 14, 2025.**

5. If Atikokan Hydro Inc. updates the proposed Tariff of Rates and Charges, it may file with the OEB and forward to VECC, responses to any comments on its draft rate order by **April 22, 2025**.

6. Atikokan Hydro Inc. will file at its next Cost of Service application an in-house summary of its assets by asset type and the number of assets in each of its condition ratings based on data available at the time.

7. Atikokan Hydro Inc. will internally investigate, on a best-efforts basis, ways to improve or reduce its Activity and Program-Based Benchmarking OM&A unit costs and report back at its next Cost of Service application on the areas investigated and the results.

Please quote file number, **EB-2024-0008** for all materials filed and submit them in searchable/unrestricted PDF format with a digital signature through the OEB's online filing portal.

- Filings should clearly state the sender's name, postal address, telephone number and e-mail address.

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

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

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

DATED at Toronto **March 27, 2025**

ONTARIO ENERGY BOARD

Nancy Marconi Digitally signed by Nancy Marconi
Date: 2025.03.27 14:16:05 -04'00'

Nancy Marconi
Registrar

SCHEDULE A

DECISION AND ORDER

SETTLEMENT PROPOSAL

ATIKOKAN HYDRO INC.

EB-2024-0008

MARCH 27, 2025

ATIKOKAN HYDRO

117 Gorrie Street, Box 1480
Atikokan, Ontario P0T 1C0

Telephone (807)597-6600
Fax (807)597-6988
e-mail jen.wiens@athydro.com
Website: www.athydro.com

March 20, 2025

Ms. Nancy Marconi,
Registrar
Ontario Energy Board 2300 Yonge
Street 27th Floor
Toronto, Ontario M4P 1E4

Dear Ms. Marconi:

Re: Atikokan Hydro Inc. Cost of Service, EB-2024-0008
Distribution Rate Application for Rates Effective May 1, 2025
Settlement Proposal

Please find enclosed the Settlement Proposal for the above-noted proceeding.

Please contact the undersigned for any questions.

Sincerely,

Jennifer Wiens

Jennifer Wiens
CEO/Sec/Treasurer
Atikokan Hydro Inc.

Cc: all Parties

EB-2024-0008

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
Atikokan Hydro Inc.
For an order approving just and reasonable rates and
Other charges for electricity distribution beginning
May 1, 2025.

Atikokan Hydro Inc.

Settlement Proposal

Filed: March 20, 2025

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Live Excel Models

Atikokan Hydro Inc. has filed revised models as evidence to support this Settlement Proposal. The models have been filed through the OEB's e-filing service and include:

- Chapter 2 Filing Requirement Appendices
- Revenue Requirement Workform
- GA Analysis Workform
- Text Year Income Tax PILS Model
- Load Forecast Model
- Load Profile
- Cost Allocation Model
- DVA Continuity Schedule Model
- RTSR Workform Model
- Tariff Schedule and Bill Impact Model

SETTLEMENT PROPOSAL

Atikokan Hydro Inc. (the "Applicant" or "Atikokan") filed a Cost of Service application with the Ontario Energy Board (the OEB) on October 30, 2024 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 Atikokan charges for electricity distribution, to be effective May 1, 2025 (OEB file number EB-2024-0008) (the "Application").

The OEB issued a completeness letter November 13, 2024 and published a Notice of Hearing dated November 21, 2024.

The OEB also issued a Letter of Direction and Notice of Application on November 21, 2024. In Procedural Order No. 1, dated December 16, 2024, the OEB approved the request of the Vulnerable Energy Consumers Coalition (VECC) to be an intervenor in this proceeding. The Procedural Order also indicated the prescribed dates for a one-day Issues Day meeting, and a settlement conference.

On January 13, 2025, the OEB issued a direction that OEB staff would be a party to the settlement conference and to any resulting settlement proposal.

All parties (i.e, OEB staff, VECC and Atikokan) participated in a one-day Issues Day meeting held January 15, 2025.

On January 21, 2025, OEB staff, on behalf of all the parties, submitted a proposed issues list to the OEB for approval. The OEB approved the Issues List on February 4, 2025. The OEB also accepted the mutually agreed to list of evidentiary clarifications, updates and corrections to be made by Atikokan (commitment responses).

Atikokan filed its commitment responses with the OEB on February 19, 2025.

A settlement conference was convened virtually on February 24-25 and March 4, 2025 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").

Atikokan and the following participated in the Settlement Conference

- VECC,
- OEB staff

OEB Commissioner Allison Duff acted as a facilitator for the Settlement Conference.

Atikokan, VECC and OEB staff (collectively the "Parties"), reached a full settlement regarding Atikokan's 2025 Cost of Service Application. The details and specific components of the settlement are detailed in this Settlement Proposal.

This document is called a "Settlement Proposal" as this is a proposal by the Parties presented 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 approval of this Settlement Proposal, this document is intended to be a legal agreement, creating mutual obligations, and is 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 herein.

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 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, and b) the Appendices to this document. The supporting Parties for each settled issue, as applicable, agree that the evidence in respect of that settled issue, is sufficient in the context of the overall settlement to support the proposed settlement, and the sum of the evidence in this proceeding provides an appropriate evidentiary record to support acceptance by the OEB of this Settlement Proposal. The Parties agree that references to the evidence in this Settlement Proposal shall, unless the context otherwise requires, include, in addition to the Application, the commitment responses, and all other components of the record up to and including the date hereof, including additional information included by the Parties in this Settlement Proposal and the Attachments to this document.

Included with the Settlement Proposal are Attachments that provide further support for the proposed settlement. The Parties acknowledge that the Attachments were prepared by Atikokan. While VECC and OEB staff have reviewed the Attachments, they are relying on the accuracy of the underlying evidence in entering into this Settlement Proposal.

For ease of reference, this Settlement Proposal follows the format of the final Approved Issues List.

The Parties are pleased to advise the OEB that a complete settlement with respect to all of the issues in this proceeding was reached, specifically:

Description	Number of issues settled
“Complete Settlement “means an issue for which complete settlement was reached by all Parties, and if this Settlement Proposal is accepted by the OEB, the Parties will not adduce any evidence or argument during the hearing in respect of these issues.	**All**
“Partial Settlement” means an issue for which there is partial settlement as Atikokan and the other Parties who take any position on the issue were able to agree on some but not all aspects of the particular issues. If this Settlement Proposal is accepted by the OEB, the Parties will only adduce evidence and/or argument during the hearing on those portions of the issue for which no agreement has been reached.	Not Applicable
“No Settlement” means an issue for which no settlement was reached. Atikokan and the other Parties who take a position on the issue will adduce evidence and/or argument at the hearing on the issue.	Not Applicable

Per 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 not accept may continue as a valid settlement without inclusion of any part(s) that the OEB does not accept).

If 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 Parties who took a position on an issue must agree with any revised Settlement Proposal as it relates to that issue prior to its resubmission to the OEB.

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

Where in this Agreement, the Parties “accept” the evidence of Atikokan, or “agree” to a revised term or condition, including a revised budget or forecast, then unless the Agreement expressly states to the contrary, the words “for the purpose of settlement of the issues herein” shall be deemed to qualify that acceptance or agreement.

SUMMARY

The Parties have reached a complete settlement on all aspects of the Application with respect to capital costs, operations, maintenance & administration (OM&A) costs, revenue requirement-related issues, including the accuracy of the revenue requirement determination and the application of OEB policies and practices.

In reaching this Settlement, the Parties have been guided by the Filing Requirements for 2025 rates and the Approved Issues List.

The Settlement Proposal, if accepted, results in a total bill decrease of $6.87 or 4.80% per month for the typical residential customer consuming 750 kWh per month.

The financial impact of the Settlement Proposal is to reduce the base revenue requirement requested of $1,817,018 by $174,295 to $1,642,723.

The Parties agree that Atikokan's new rates should be effective on the same date that Atikokan is able to implement them, subject to May 1, 2025, being the earliest effective date that will be permitted. The proposed new rates can be implemented for May 1, 2025, by Atikokan if approved by the OEB before May 19, 2025, which is the date the May consumption billing process begins.

The Parties note that this Settlement Proposal includes all tables, appendices and the live Excel models that represent the evidence and the settlement between the Parties at the time of filing the Settlement Proposal.

A Revenue Requirement Work Form, incorporating all terms that have been agreed to is filed as Appendix A to the Settlement Proposal. Through the settlement process, Atikokan has agreed to certain adjustments to its original Application evidence. The changes are described in the following sections.

Atikokan has provided the following tables summarizing the Application and highlighting the changes to its Rate Base and Capital, OM&A Expenses and Revenue Requirement from Atikokan's original Application evidence, the commitment responses and this Settlement Proposal.

Table 1- Summary of 2025 Revenue Requirement

	Application (a)	Commitment Responses (b)	Variance (c) = (b)-(a)	Settlement (d)	Variance (e) = (d)-(b)
Long Term Debt	6.7%	4.66%	-2.04%	4.66%	0.00%
Short Term Debt	6.23%	5.04%	-1.19%	5.04%	0.00%
Return on Equity	9.21%	9.25%	-0.004%	9.25%	0.00%
Regulated Rate of Return	**7.69%**	**6.51%**	**-1.18%**	**6.51%**	**0.00%**
Controllable Expenses	$1,369,267	$1,369,267	$0	$1,364,267	($5,000)
Cost of Power	$3,155,979	$3,100,459	($55,520)	$3,157,262	$56,803
Total Eligible Distribution Expenses	$4,525,246	$4,469,726	($55,520)	$4,521,529	$51,803
Working Capital Allowance Rate	7.5%	7.5%	0.00%	7.5%	0.00%
Working Capital Allowance	**$339,393**	**$335,229**	**($4,164)**	**$339,115**	**$3,886**
Gross Fixed Assets (avg)	$8,290,346	$8,200,375	($89,971)	$8,167,875	($32,500)
Accumulated Depreciation (avg)	$(4,816,116)	$(4,824,455)	($8,339)	$(4,703,692)	$120,764
Net Fixed Assets (avg)	$3,474,230	$3,711,150	$236,920	$3,464,184	($246,966)
Working Capital Allowance	$339,393	$335,229	($4,164)	$339,115	$3,886
Rate Base	**$3,812,623**	**$3,711,150**	**($101,473)**	**$3,803,298**	**$92,148**
Regulated Rate of Return	7.69%	6.51%	-1.18%	6.51%	0.00%
Regulated Return on Capital	**$293,085**	**$241,641**	**($51,444)**	**$247,640**	**$5,999**
Deemed Interest Expense	$152,591	$137,313	($15,278)	$106,918	($30,395)
Deemed Return on Equity	$140,494	$137,313	($3,181)	$140,722	$3,409
OM&A Expense	$1,340,301	$1,340,301	$0	$1,335,301	($5,000)
Depreciation Expense	$247,835	$204,780	($43,055)	$205,111	$331
Property Tax	$28,966	$28,966	$0	$28,966	$0
Income Tax (PILS)	$1,445	0	($1,445)	0	$0
Service Revenue Requirement	**$1,911,632**	**$1,815,687**	**($99,945)**	**$1,817,018**	**$1,331**
Revenue Offset	$173,258	$175,817	$2,559	$174,295	($1,522)
Base Revenue Requirement	**$1,738,374**	**$1,639,870**	**($98,504)**	**$1,642,723**	**$2,853**
Revenue Sufficiency/Deficiency	$115,661	$22,930	($92,731)	$22,476	$454

Based on the above, and the evidence and rationale provided below, the Parties accept this Settlement Proposal as appropriate and recommend its acceptance by the OEB. Tables 2 and 3 below illustrate the updated bill impacts that would result from the acceptance of this Settlement Proposal. The updated bill impacts are also included in Appendix D of this proposal.

Table 2 - 2025 Summary of Total Bill Impacts

Rate Class	Usage		Current Rates	2025 Proposed Rates	$	%
	kWh	kW	Total Bill $	Total Bill $	Difference	Difference
Residential - RPP	750		142.97	136.10	(6.87)	-4.80%
Residential - RPP	141		61.00	56.97	(4.02)	-6.60%
Residential - RPP	547		115.64	109.72	(5.92)	-5.12%
Residential - non-RPP (retailer)	750		138.52	132.84	(5.68)	-4.10%
GS<50 kW - RPP	2,000		365.43	349.75	(15.68)	-4.29%
GS <50 kW -RPP	3,000		503.10	479.58	(23.52)	-4.68%
GS<50 kW – non-RPP (retailer)	2,000		353.99	341.48	(12.51)	-3.53%
GS > 50 to 4,999 kW – non-RPP (retailer)	83,882	190	13,464.07	13,156.55	(307.52)	-2.28%
GS > 50 to 4,999 kW – non-RPP (other)	72,337	125	11,233.69	11,023.28	(210.41)	-1.87%
GS> 50 to 4,999 kW – non-RPP (other)	433,900	1,304	71,169.41	69,195.91	(1,973.49)	-2.77%
GS> 50 to 4,999 kW – non-RPP (other)	15,348	55	2,939.70	2,864.73	(74.97)	-2.55%
GS>50 to 4,999 kW – non-RPP (Other)	32,850	87	5,883.87	5,745.68	(138.19)	-2.35%
Street Lighting -non-RPP (other)	43,319	93	19,070.44	18,437.00	(633.44)	-3.32%

Table 3 - 2025 Proposed Rates – Summary of Monthly Change

Rate Class	Usage		A - Sub-Total Distribution		B – Sub-Total Distribution with DVA		C – Sub-Total Total Delivery		Total Bill Impact	
	kWh	kW	$	%	$	%	$	%	$	%
Residential - RPP	750		(3.37)	-8.1%	(8.16)	-16.3%	(6.79)	-10.7%	(6.87)	-4.8%
Residential - RPP	141		(3.37)	-8.1%	4.27	9.9%	4.01	8.7%	(4.02)	-6.6%
Residential - RPP	547		(3.37)	-8.1%	(6.87)	-14.4%	(5.86)	-10.2%	(5.92)	-5.12%
Residential - non-RPP (retailer)	750		(3.37)	-8.1%	(6.97)	-13.1%	(5.60)	-8.4%	(5.68)	-4.1%
GS<50 kW - RPP	2,000		(5.80)	-5.8%	(18.58)	-15.1%	(15.47)	-10.0%	(15.68)	-4.3%
GS <50 kW -RPP	3,000		(8.70)	-8.2%	(27.87)	-19.9%	(23.20)	-12.4%	(23.52)	-4.7%
GS<50 kW – non-RPP (retailer)	2,000		(5.80)	-5.8%	(15.21)	-11.7%	(12.29)	-7.5%	(12.51)	-3.5%
GS > 50 to 4,999 kW – non-RPP (retailer)	83,882	190	(75.89)	-5.1%	(250.67)	-12.1%	(119.67)	-3.8%	(307.52)	-2.3%
GS > 50 to 4,999 kW – non-RPP (other)	72,337	125	(49.93)	-4.1%	(140.90)	-8.4%	(54.72)	-2.3%	(210.41)	-1.87%
GS> 50 to 4,999 kW – non-RPP (other)	433,900	1,304	(520.82)	-8.14%	(1,918.91)	-20.06%	(957.73)	-5.39%	(1,973.49)	-2.77%
GS> 50 to 4,999 kW – non-RPP (other)	15,348	55	(21.97)	-2.43%	(85.07)	-8.32%	(47.15)	-3.51%	(74.97)	-2.55%
GS>50 to 4,999 kW – non-RPP (Other)	32,850	87	(34.75)	-3.33%	(122.56)	-9.60%	(62.58)	-3.51%	(138.19)	-2.35%
Street Lighting -non-RPP (other)	43,319	93	(608.21)	-5.2%	(530.41)	-4.4%	(481.82)	-3.9%	(633.44)	-3.3%

1. Capital Spending and Rate Base

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

Full Settlement

The Parties agree to Atikokan's proposed 2025 capital expenditures and 2025 net capital in-service additions for the purpose of setting rates, subject to adjustments in settlement.

Atikokan filed for $634,274 in 2025 net capital expenditures. As part of the commitment responses, Atikokan updated the 2024 rate base for the 2024 audited capital spending and depreciation, thereby adjusting the opening balances of the test year. The 2025 test year project costs in-service additions were also updated as part of the commitment responses. In addition, the Parties agree to the following adjustments through settlement:

- Atikokan to reduce its System Renewal 2025 capital spend by $15,000.
- Atikokan to include an additional $50,000 in capital contributions for 2025. While Atikokan had no plans of capital contributions in its prior cost of service, for its distribution system plan period, Atikokan received an annual average capital contribution of $50,000 for the historical years of 2019 through 2023. The Parties agree it was reasonable for Atikokan to receive an additional $50,000 in the test year. The Parties also agree to include an additional $50,000 annually to 2026 through 2029. Atikokan's added these contributions to System Renewal.
- Atikokan to increase the 2025 test year capital expenditures by an additional $5,038 to include distribution station equipment upgrades as listed in Commitment Response 1b. Atikokan Hydro had inadvertently omitted the expenditure from its capital expenditure plan models as part of its commitment responses.

The following table summarizes the agreed upon capital expenditures and in-service additions for the test year by Category - net of any capital contributions.

Table 4 – 2025 Capital Expenditures/In-Service Additions

Particulars	Application (a)	Commitment Responses (b)	Variance (c) = (b)-(a)	Settlement (d)	Variance (e) = (d)-(b)
System Access	$165,274	$180,548	$15,274	$180,548	$0
System Renewal	$185,000	$185,000	$0	$175,038	(9,962)
System Service	$200,000	$565,000	$365,000	$565,000	$0

General Plant	$384,000	$384,000	$0	$384,000	$0
Total Expenditures	$934,274	$1,314,548	$380,274	$1,304,586	($9,962)
Capital Contributions	($300,000)	($773,000)	($473,000)	($823,000)	(50,000)
Net Capital Expenditures	$634,274	$541,548	($92,726)	$481,586	($59,962)

The Parties accept the evidence of Atikokan that the level of planned capital expenditures over the course of its Distribution System Plan and the rationale for planning and pacing choices are appropriate to maintain system reliability, service quality objectives and reliable and safe operations of the distribution system. The net 2025 test year in-service additions budget of $482k is 73% greater than the net historical average in-service additions of $279k (2017-2024). The increase in the 2025 test year budget is attributable to the purchase of a backyard track machine for $350k. The Parties believe this expenditure is prudent given Atikokan's assertion that the truck will allow for better access to cut trees as well as better access to some off-road poles that are inaccessible with Atikokan's current fleet.[1]

Atikokan indicates it has age data related to its assets but has less information on its condition ratings by asset type and no data was provided in this application. At its next Cost of Service application, Parties agreed that Atikokan has committed to providing a summary of assets by asset type and the number of assets in each of its condition ratings based on data available at the time. The Parties agree that the summary can be done in-house to avoid third-party costs using Atikokan's asset management data.[2]

Evidence References

- Exhibit 1 _ Administrative Document
- Exhibit 2 – Rate Base
- Exhibit 2- Distribution System Plan

Commitment (IR) Questions

- Q1
- Q2
- Q3
- Q4
- Q5
- Q6
- Q7
- Q8

[1] Distribution System Plan 2025-2029, p.101

[2] Distribution System Plan 2025-2029, p.31

Supporting Parties

All

1.2 Are the proposed rate base and depreciation amounts appropriate?

Full Settlement

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

Changes in rate base and depreciation in the Settlement Proposal resulted from settlement on all issues that were flowed through to depreciation and rate base calculations.

The Parties agree to the updated depreciation expense which reflects the updated 2025 opening fixed assets updated for the 2024 additions and updated 2025 in-service capital additions.

The Parties agree that the working capital calculations have been appropriately determined in accordance with OEB policies and practices. Atikokan utilizes the OEB default allowance for working capital of 7.5% of the sum of cost of power and controllable expenses.

The Parties accept the evidence that the rate base calculations, after making the adjustments as detailed in this Settlement Proposal, are reasonable and have been appropriately determined in accordance with OEB policies and practices. Table 5 below outlines Atikokan's Rate Base calculation.

Table 5 - 2025 Rate Base

Particulars	Application (a)	Commitment Responses (b)	Variance (c) = (b)-(a)	Settlement (d)	Variance (e) = (d)-(b)
Gross Fixed Assets (avg)	$8,290,346	$8,200,375	($89,971)	$8,167,875	-$32,500
Accumulated Depreciation (avg)	-$4,816,116	-$4,824,455	$8,339	-$4,703,692	$120,763
Net Fixed Assets (avg)	$3,474,230	$3,375,920	($98,310)	$3,464,184	$88,264
Allowance for Working Capital	$339,393	$335,229	-$4,164	$339,115	$3,886
Total Rate Base	$3,813,623	$3,711,150	($102,474)	$3,803,298	$92,149

Table 6 - 2025 Depreciation Expense

Particulars	**Application (a)**	**Commitment Responses (b)**	**Variance (c) = (b)-(a)**	**Settlement (d)**	**Variance (e) = (d)-(b)**
Depreciation Expense	$247,835	$204,780	-$43,055	$205,111	$305,331

- While capital spending was reduced during settlement, depreciation increased by $331; the net of the two following adjustments: Decrease of $166 for removal of $15,000 in system renewal CAPEX
- Increase of $497 for computer software fully amortized

Evidence References

- Exhibit 2 – Rate Base
- Exhibit 2 – Distribution System Plan
- Chapter 2 Appendices 2BA

Commitment (IR) Questions

- Q9

Supporting Parties

All

2. OM&A

2.1 Are the proposed OM&A expenditures appropriate?

Full Settlement

The Parties agree that Atikokan will reduce its proposed OM&A expenses in the 2025 Test Year by $5,000, resulting in a 2025 Test Year OM&A Budget of $1,335,301.
The Parties also agree that Atikokan will manage its OM&A budget as it sees fit. Atikokan has applied the $5,000 reduction in operations for purposes of the settlement.
As shown below, Total 2025 Settlement Test Year OM&A Expenses have increased by $202,354 compared to the 2017 Actuals, representing an annual growth rate of approximately 2.23%. It is expected that Atikokan will remain in Group 3 productivity rating in 2025.

The Parties have also agreed that, on a best-efforts basis, Atikokan will internally investigate ways to improve or reduce its Activity and Program-Based Benchmarking (APB) unit costs in Table 13 at Exhibit 1 Page 33 and report back at its next Cost of Service application on the areas investigated and the results.

Appendix 2-JA

Summary of Recoverable 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 Actuals	2024 Bridge Year	2025 Test Year
Reporting Basis										
Operations	$ 376,877	$ 441,293	$ 419,737	$ 396,072	$ 438,048	$ 387,285	$ 412,872	$ 375,225	$ 470,041	$ 439,842
Maintenance	$ 120,741	$ 102,932	$ 86,747	$ 99,359	$ 78,733	$ 119,321	$ 128,373	$ 155,191	$ 174,819	$ 173,697
SubTotal	**$ 497,618**	**$ 544,225**	**$ 506,485**	**$ 495,432**	**$ 516,781**	**$ 506,606**	**$ 541,245**	**$ 530,416**	**$ 644,860**	**$ 613,539**
%Change (year over year)		9.4%	-6.9%	-2.2%	4.3%	-2.0%	6.8%	-2.0%	21.6%	-4.9%
%Change (Test Year vs Last Rebasing Year - Actual)										12.7%
Billing and Collecting	$ 184,336	$ 172,365	$ 177,401	$ 177,818	$ 177,886	$ 182,332	$ 178,502	$ 187,912	$ 198,061	$ 213,543
Community Relations	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		
Administrative and General	$ 415,442	$ 416,357	$ 408,261	$ 415,798	$ 419,084	$ 428,982	$ 461,285	$ 473,188	$ 497,455	$ 508,219
SubTotal	**$ 599,778**	**$ 588,722**	**$ 585,661**	**$ 593,616**	**$ 596,970**	**$ 611,314**	**$ 639,787**	**$ 661,100**	**$ 695,516**	**$ 721,763**
%Change (year over year)		-1.8%	-0.5%	1.4%	0.6%	2.4%	4.7%	3.3%	5.2%	3.8%
%Change (Test Year vs Last Rebasing Year - Actual)										22.6%
Total	**$ 1,097,396**	**$ 1,132,947**	**$ 1,092,146**	**$ 1,089,048**	**$ 1,113,751**	**$ 1,117,919**	**$ 1,181,032**	**$ 1,191,516**	**$ 1,340,376**	**$ 1,335,301**
%Change (year over year)		3.2%	-3.6%	-0.3%	2.3%	0.4%	5.6%	0.9%	12.5%	-0.4%

	2017 Last Rebasing Year OEB Approved	2017 Last Rebasing Year Actuals	2018 Actuals	2019 Actuals	2020 Actuals	2021 Actuals	2022 Actuals	2023 Actuals	2024 Bridge Year	2025 Test Year
Operations[4]	$ 376,877	$ 441,293	$ 419,737	$ 396,072	$ 438,048	$ 387,285	$ 412,872	$ 375,225	$ 470,041	$ 439,842
Maintenance[5]	$ 120,741	$ 102,932	$ 86,747	$ 99,359	$ 78,733	$ 119,321	$ 128,373	$ 155,191	$ 174,819	$ 173,697
Billing and Collecting[6]	$ 184,336	$ 172,365	$ 177,401	$ 177,818	$ 177,886	$ 182,332	$ 178,502	$ 187,912	$ 198,061	$ 213,543
Community Relations[7]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Administrative and General[8]	$ 415,442	$ 416,357	$ 408,261	$ 415,798	$ 419,084	$ 428,982	$ 461,285	$ 473,188	$ 497,455	$ 508,219
Total	**$ 1,097,396**	**$ 1,132,947**	**$ 1,092,146**	**$ 1,089,048**	**$ 1,113,751**	**$ 1,117,919**	**$ 1,181,032**	**$ 1,191,516**	**$ 1,340,376**	**$ 1,335,301**
%Change (year over year)		3.2%		-3.9%	2.3%	0.4%	5.6%	0.9%	12.5%	-0.4%

A summary of the OM&A expenditures is presented in Table 7 below.

Table 7- 2025 Test Year OM&A Expenditures

	Application (a)	Commitment Responses (b)	Variance (c) = (b)-(a)	Settlement (d)	Variance (e) = (d)-(b)
Operations	$444,842	$444,842	$0	$439,842	$(5,000)
Maintenance	$173,697	$173,697	$0	$173,697	$0
Billing and Collecting	$213,543	$213,543	$0	$213,543	$0
Community Relations	$0	$0	$0	$0	$0
Administration & General +LEAP	$508,209	$508,209	$0	$508,209	$0
Total	$1,340,301	$1,340,301	$0	$1,335,301	$(5,000)

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

Full Settlement

The Parties agree that Atikokan's proposed shared services cost allocation methodology and the quantum are appropriate.

Evidence References

- Exhibit 1 – Administrative Documents
- Exhibit 4 – OM&A

Commitment (IR) Questions

- Q10
- Q11

Supporting Parties

All

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?

Full Settlement

The Parties agree to the cost of capital parameters issued by the OEB set out below in Table 8. Parties have also agreed to use the OEB's long term debt rate instead of the weighted average cost of long term debt rate.

Table 8 - 2025 Cost of Capital

Capital Structure:	Application (a)	Commitment Responses (b)	Settlement (c)	Settlement Dollars (d)
Long-term debt Capitalization Ratio (%)	56.0%	56.0%	56.0%	$2,129,847
Short-term debt Capitalization Ratio (%)	4.0%	4.0%	4.0%	$152,132
Common Equity Capitalization Ratio (%)	40.0%	40.0%	40.0%	$1,521,319
Preferred Shares Capitalization Ratio (%)	0.0%	0.0%	0.0%	
	100.0%	100.0%	100.0%	$3,803,298
Cost of Capital				
Long-term debt Cost Rate (%)	6.70%	4.66%	4.66%	$2,129,847
Short-term debt Cost Rate (%)	6.23%	5.04%	5.04%	$152,132
Common Equity Cost Rate (%)	9.21%	9.25%	9.25%	$1,521,319
TOTAL		6.51%	6.51%	$3,803,298

The Parties agree that Atikokan Hydro will comply with any orders or directions from the OEB resulting from the Cost of Capital Generic Proceeding that are applicable to Atikokan Hydro. The Parties agree that Atikokan Hydro shall: (a) use the interim cost of capital parameters and the deferral and variance accounts from the OEB letter dated October 31, 2024 from EB-2024-0063; and (b) shall use the interim deemed short term debt rate and deferral and variance account established in the OEB letter dated July 26, 2024 to capture the revenue requirement impact from the changes to the deemed short term debt rate described therein.

Evidence References
- Exhibit 1 – Administrative Document
- Exhibit 5 – Cost of Capital and Capital Structure

Commitment (IR) Questions
- None

Supporting Parties

All

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

Full Settlement

For the purposes of settlement of all the issues in this proceeding, and subject to the other adjustments arising in this Settlement Proposal, the Parties accept the evidence of Atikokan that its forecast PILs, as updated for the settlement agreement is appropriate and has been correctly determined in accordance with OEB accounting policies and practices.

The parties accept Atikokan's calculations of forecast PILs in this Settlement Proposal resulting in NIL PILS embedded in rates.

A summary of the adjusted PILs to use accelerated CCA in the test year is presented in Table 9 below.

Table 9 - 2025 Payment in Lieu of Taxes

Particulars	Application (a)	Commitment Responses (b)	Variance (c) = (b)-(a)	Settlement (d)	Variance (e) = (d)-(b)
PILs (Grossed up)	$1,445	$0	-$1,445	$0	$0

An updated PILs Model has been submitted in Live Excel format as part of this Settlement Proposal.

Evidence References
- Exhibit 1 – Administrative Documents
- Exhibit 6 – Revenue Requirement and Revenue Deficiency or Sufficiency
- Test Year Income Tax/PILs Work Form

Commitment (IR) Questions

- Q12

Supporting Parties

All

3.3 Is the proposed Other Revenue forecast appropriate?

Full Settlement

The Parties accept the evidence provided by Atikokan that its proposed Other Revenues are appropriate and have been correctly determined in accordance with OEB accounting policies and practices.

The Parties agree to other revenue income of $174,295, net of the following settlement adjustments.

Table 10 – Other Revenue Settlement Adjustments

Other Income Account	Application (a)	Commitment Responses (b)	Variance (c)=(b)-(a)	Settlement (d)	Variance (e) =(d)-(b)	Change Explanation
4210 - Rent from Electric Property	$61,615	$64,174	$2,559	$64.174	$0	Correction to pole attachment revenue to account for 2025 test year Board Approved attachment rate
4245 - Government & Other Assistance Income	$30,726	$30,726	$0	$33,204	$2,478	Deferred revenue adjusted for agreed contributions for the test year
4405 - Interest and Dividend Income	$18,000	$18,000	$0	$14,000	$(4,000)	Exclusion of DVA Interest
			$2,559	Net Variance	$-1,522	

The breakdown of the agreed other revenue is summarized in Table 11 below.

Table 11- 2025 Summary of Other Revenues

	Application (a)	Commitment Responses (b)	Variance (c) = (b)-(a)	Settlement (d)	Variance (e) = (d)-(b)
Specific Service Charges	$4,872	$4,872	$0	$4,872	$0
Late Payment Charges	$7,572	$7,572	$0	$7,572	$0
Other Distribution/Operating Revenues	$4,850	$4,850	$0	$4,850	$0
Other Income or Deductions	$155,964	$158,523	$2,559	$157,001	-$1,522
Total	$173,258	$175,817	$0	$174.295	$0

Evidence References

- Chapter 2 Appendices 2H
- Exhibit 6 - Revenue Requirement and Revenue Deficiency or Sufficiency

Commitment (IR) Questions

- Q14

Supporting Parties

All

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?

Full Settlement

The Parties accept the evidence of Atikokan that all impacts of any changes to 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 References

- Exhibit 1 – Administrative Document
- Exhibit 4 – OM&A
- Exhibit 6 - Revenue Requirement and Revenue Deficiency or Sufficiency

Commitment (IR) Responses

- None

Supporting Parties

All

3.5 Is the proposed calculation of the Revenue Requirement appropriate?

Full Settlement

The Parties agree that the methodology used by Atikokan to calculate the Revenue Requirement is appropriate.

A summary of the Base Revenue Requirement of $1,642,723 reflecting adjustments and settled issues is presented in the Revenue Requirement Summary below.

Table 12 - 2025 Revenue Requirement

	Application (a)	Commitment Responses (b)	Variance (c) = (b)-(a)	Settlement (d)	Variance (e) = (d)-(b)
OM&A Expenses	$1,340,301	$1,340,301	$0	$1,335,301	($5,000)
Amortization/Depreciation	$247,835	$204,780	-$43,055	$205,111	($331)
Property Taxes	$28,966	$28,966	$0	$28,966	$0
Income Taxes (Grossed up) (PILS)	$1,445	$0	-$1,445	$0	$0
Other Expenses	-	-	-	-	-
Return					
Deemed Interest Expense	$152,591	$104,328	($48,263)	$106,918	($2,590)
Return on Deemed Equity	$140,494	$137,313	-$3,181	$140,722	$3,409
Service Revenue Requirement (before Revenues)	$1,911,632	$1,815,687	($195,945)	$1,817,018	$1,331
Revenue Offsets	$173,258	$175,817	$2,559	$174,295	($1,522)
Base Revenue Requirement	$1,738,374	$1,639,870	$98,504	$1,642,723	$2,853
Grossed up Revenue Deficiency	$115,661	$22,930	($92,731)	$22,476	-$454

An updated Revenue Requirement Work Form Model has been filed as part of the Settlement Proposal.

Evidence References

- Exhibit 6 - Revenue Requirement and Revenue Deficiency or Sufficiency

Commitment (IR) Responses

- **None**

Supporting Parties

All

4. Load Forecast

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

Full Settlement

The Parties agree that the updated load forecast provided in the commitment responses is appropriate for the purpose of setting rates. The updated load forecast filled with this Settlement Proposal includes incorporating actual consumption and customer count data for 2024 that was not filed with the original application as it was unavailable at the time of filing. Further, the Parties agree that the pre-established Street Lighting demand values for 2025 would be used in the load forecast given the absolute certainty of the preset values producing an accurate as possible forecast. The details of the billing determinate updates are provided in Table 13 through Table 15 below.

Evidence References

- Exhibit 3 – Operating Revenue
- Atikokan Load Forecast Model
- Atikokan Load Profile Model

Commitment (IR) Responses

- Q16
- Q17
- Q18

Supporting Parties

All

Table 13 - Summary of Load Forecast Billed kWh

Particulars	Application (a)	Commitment Responses (b)	Variance (c) = (b)-(a)	Settlement (d)	Variance (e) = (d)-(b)
Residential	8,776,264	8,853,697	77,433	8,867,818	14,121
General Service < 50 kW	4,495,158	4,712,336	217,178	4,719,852	7,516
General Service > 50 to 4999 kW	15,506,375	14,914,371	592,004	14,933,631	19,260
Street Lighting	341,006	355,073	14,067	314,176	(40,897)
Total kWh	29,118,803	28,835,477	-283,326	28,835,477	0

Table 14 - Summary of Load Forecast kW

Particulars	Application (a)	Commitment Responses (b)	Variance (c) = (b)-(a)	Settlement (d)	Variance (e) = (d)-(b)

Residential					
General Service < 50 kW					
General Service > 50 to 4999 kW	46,637	44,856	(1,781)	44,938	82
Street Lighting	1058	1058	0	956.52	(101.48)
Total kW	47,695	45,914	(1,781)	45,895	(19)

Table 15 - Summary of Load Forecast Customers / Connections

Particulars	Application (a)	Commitment Responses (b)	Variance (c) = (b)-(a)	Settlement (d)	Variance (e) = (d)-(b)
Residential	1365	1368	3	1368	0
General Service < 50 kW	232	234	2	234	0
General Service > 50 to 4999 kW	15	15	0	15	0
Street Lighting	622	622	0	622	0
Total kW	35,532	35,532	0	2,239	0

5. Cost Allocation, Rate Design, and Other Charges

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

The Parties accept the evidence of Atikokan that, subject to the adjustments identified below, the cost allocation methodology, allocations and revenue-to-cost ratios are appropriate.

Atikokan agrees to balance its revenue requirement across customer classes by moving the revenue to cost ratios to the edge of the OEB range, if outside of the range, and then beginning with the lowest revenue to cost ratios, as determined by the cost allocation model, increasing it until it matches the next lowest revenue to cost ratio, then continuing to increase each in this manner until the revenue requirement is balanced.

Further, the Parties agree that, because Atikokan has sub-transmission lines, the sub-transmission asset value from the primary asset account 1830 should be allocated to sub-transmission asset account 1835 for calculation of the cost allocation model. This methodology is consistent with that used in Atikokan's previous 2017 Cost of Service Settlement Proposal.[3] The balance of the assets in account 1830 are assumed to be 31.84% primary and 68.16% secondary.

Table 16 sets out the revenue to cost ratios settled upon by the Parties.

[3] EB-2016-0056, Settlement Proposal, p. 31

Table 16 - Proposed 2025 Revenue to Cost Ratios

	Application			Commitment Responses			Settlement		
Rate Class	**Calculated R/C Ratio**	**Proposed R/C Ratio**	**Var**	**Calculated R/C Ratio**	**Proposed R/C Ratio**	**Var**	**Calculated R/C Ratio**	**Proposed R/C Ratio**	**Var**
Residential	96.38%	97.28%	0.90%	96.11%	96.11%	0.00%	98.92%	98.92%	0.00%
General Service < 50 kW	118.68%	118.69%	0.01%	119.09%	119.09%	0.00%	116.95%	116.95%	0.00%
General Service > 50 to 4999 kW	83.20%	83.21%	0.01%	82.82%	84.32%	1.50%	84.88%	85.07%	0.19%
Street Lighting	161.58%	151.88%	-9.70%	161.20%	154.95%	-6.25%	120.58%	120.00%	-0.58%

The Parties accept the evidence of Atikokan that all elements of the cost allocation methodology allocation and Revenue-to-Cost ratios have been correctly determined in accordance with OEB policies and practices. Further the proposed revenue-to-cost ratios for all rate classes are within the OEB policy range; 85-115% for residential and 80-120% respectively for all other rate classes.

The Parties further accept Atikokan's updated Load Profile demand allocators calculation and agree to the scaled demand allocators to the 2025 consumption forecast.

Evidence References

- Exhibit 7 – Cost Allocation

Commitment (IR) Responses

- Q19

Supporting Parties

All

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

Full Settlement

The Parties agree to the rate design including fixed/variable splits included in the Settlement Proposal. The Parties also agree that for all rate classes, except for residential which is fully fixed, where the current fixed service charge is greater than the minimum Peak Load Carrying Capability (PLCC), the current fixed service charge would be maintained, and the volumetric variable rate would be adjusted accordingly. The Parties further agree to keep the fixed service charges for the GS > 50, GS < 50 and Street Lighting customer classes at the 2024 OEB's approved rates and adjust the volumetric rates accordingly, in accordance with OEB Policy.[4]

Table 19 - Summary of 2025 Fixed to Variable Split

Rate Class	Application		Settlement Proposal	
	Fixed %	Variable %	Fixed %	Variable %
Residential	100.00%	0.00%	100.00%	0.00%
General Service < 50 kW	91.12%	8.88%	89.55%	10.45%
General Service > 50 to 4999 kW	38.16%	61.84%	38.35%	61.65%
Street Lighting	90.92%	9.08%	90.91%	9.09%

Evidence References

- Exhibit 7 – Cost Allocation
- Exhibit 8 – Rate Design

Commitment (IR) Questions

- Q19

Supporting Parties

All

5.3 Are the proposed Retail Transmission Service rates appropriate?

Full Settlement

The Parties accept the evidence of Atikokan that all elements of the Retail Transmission Service Rates have been correctly determined in accordance with OEB policies and practices. The Parties accept that the RTSR rates as updated for the 2025 UTRs and presented in the table below are appropriate.

EB-2016-0056, Settlement Proposal, p. 31
cation of Cost allocation for Electricity Distributors, November 28, 2007, pp. 12-13

Table 2025- RTSR Network and Connection Rates

–Rate Description	Application (a)	Commitment Responses (b)	Variance (c) = (b)-(a)	Settlement (d)	Variance (e) = (d)-(b)
Network Service Rate					
Residential	$0.0106	$0.0117	$0.0011	$0.0117	$0.0000
General Service < 50 kW	$0.0092	$0.0102	$0.001	$0.0102	$0.0000
General Service > 50 to 4999 kW	$3.7774	$4.1630	$0.3856	$4.1630	$0.0000
General Service > 50 to 4999 kW–Interval Metered	$4.0076	$4.4167	$0.4091	$4.4167	$0.0000
Street Lighting	$2.8491	$3.1399	$0.2908	$3.1399	$0.0000
Line and Transformation Connection Service Rate					
Residential	$0.0065	$0.0069	$0.0004	$0.0069	$0.0000
General Service < 50 kW	$0.0054	$0.0057	$0.0003	$0.0057	$0.0000
General Service > 50 to 4999 kW	$2.2475	$2.3735	$0.126	$2.3735	$0.0000
General Service > 50 to 4999 kW–Interval Metered	$2.4839	$2.6232	$0.1393	$2.6232	$0.0000
Street Lighting	$1.7373	$1.8348	$0.0975	$1.8348	$0.0000

Evidence References

- Exhibit 8 – Rate Design
- RTSR Model

Commitment (IR) Questions

- Q31

Supporting Parties

- All

5.4 Are the proposed loss factors Appropriate?

Full Settlement

The Parties agree to the Loss Factors proposed in settlement.

The Parties acknowledge that the Application proposed Total Loss Factor of 1.0742 was based on the five-year historical average of 2019 through 2023 per the filing requirements but the most recent 5-year average of 2020 through 2024 was consistent with the load forecast being updated to include the 2024 actual consumption and customer count/connections. As a result, the Parties believe that using the most current historical 5-year average for rate setting purposes is most appropriate.

Table 18 - 2025 Loss Factor

Particulars	Application (a)	Commitment Responses (b)	Variance (c) = (b)-(a)	Settlement (d)	Variance (e) = (d)-(b)
Loss Factor – Secondary	1.0742	1.0754	0.0012	1.0754	0
Loss Factor - Primary	1.0636	1.0648	0.012	1.0648	0

Evidence References

- Exhibit 8 – Rate Design
- Chapter 2 Appendices 2-R

Commitment (IR) Questions

- VECC-CQ-5

Supporting Parties

- All

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

Full Settlement

The Parties accept that Atikokan's proposed Specific Service Charges and Retail Service Charges are appropriate. The Retail Service Charges have been updated in accordance with the OEB Decision and Order issued September 26, 2024 (EB-2024-0226).

The Parties further agree that the final tariffs should include the fixed microFIT monthly service charge of $5.00 per the OEB letter dated November 19, 2024.

Evidence References

- Exhibit 8 – Rate Design

Commitment (IR) Questions

- None

Supporting Parties

All

5.6 Are rate mitigation proposals required and appropriate?

Full Settlement

The Parties agree no rate mitigation is required. Total bill impacts are less than 10 percent.

Evidence References

- Exhibit 8 – Rate Design

Commitment (IR) Questions

- Q19
- Q20

Supporting Parties

All

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, request for discontinuation of accounts, and continuation of existing accounts, appropriate?

Full Settlement

The Parties agree that Atikokan's proposal for deferral and variance accounts including balances in the existing accounts and their disposition, request for new accounts, requests for disposition of accounts, and the continuation of existing accounts appropriate on a final basis, subject to the following adjustments:

- the Pole Attachment variance (1508) account should be forecast to the end of April 30, 2025; disposed on final basis and account closed.
- while currently Atikokan has no costs recorded in a Cloud Computing Implementation Costs Deferral Account and no present need for an account is required; this Settlement Proposal does not preclude Atikokan from coming forward with a request to establish such an account should Atikokan implement cloud computing prior to its next Cost of Service application.
- The GA Workform was adjusted from the original Application evidence to correct clerical errors with 1589 within the unresolved difference.
- Gross up 1592 CCA Change variances previously recorded up to December 31, 2023 balances
- discontinue use of the Retail Cost variance (1518) account
- discontinue use of the STR Retail Cost variance (1548) account

The Parties further agree to the default disposition period of 12 months for the deferral and variance accounts to be cleared in the Application except for group 2 deferral and variance accounts, which are being cleared over 24 months.

Evidence References

- Exhibit 1 – Administrative Document
- Exhibit 8 – Rate Design
- Exhibit 9 – Deferral and Variance Accounts

Commitment (IR) Questions

- Q21
- Q22
- Q23
- Q24
- Q25
- Q26
- Q27

Supporting Parties

All

Table 19 below summarizes the amounts for disposition and Tables 21 through 24 shows the agreed upon rate riders by class from settlement.

Table 19 - DVA Balances for Disposition

Account Description	USoA #	Application Oct 30, 2024	Issues Day Process Jan 16, 2024	Settlement Proposal March 20, 2025	Continue use of Account
GROUP 1					
LV Variance Account	1550	0	0	0	Yes
Smart Metering Entity Charge Variance Account	1551	(3,273)	(3,251)	(3,251)	Yes
RSVA - Wholesale Market Service Charge	1580	(39,859)	(39,597)	(39,597)	Yes
RSVA – Wholesale Market Service Charge – Sub Account CBR Class B	1580	2,700	2,681	2,681	Yes
RSVA - Retail Transmission Network Charge	1584	31,583	31,388	31,388	Yes
RSVA - Retail Transmission Connection Charge	1586	13,841	13,754	13,754	Yes
RSVA - Power (excluding Global Adjustment)	1588	(53,220)	(52,890)	(52,890)	Yes
RSVA - Global Adjustment	1589	41,018	40,762	40,762	Yes
Disposition and Recovery/Refund of Regulatory Balances (2020)	1595	(29,867)	(29,695)	(29,695)	No
Total of Group 1 Accounts		**(37,077)**	**(36,847)**	**(36,847)**	
GROUP 2					
Other Regulatory Assets - Pole Attachment Revenue Variance	1508	(185,904)	(184,710)	(195,928)	No
Retail Cost Variance Account - Retail	1518	(20,169)	(20,042)	(20,042)	No
Retail Cost Variance Account - STR	1548	10,917	10,849	10,849	No

Other Regulatory - PILS and Tax Variance – CCA Changes	1592	(23,487)	(23,273)	(23,328)	Yes
Total of Group 2 Accounts		**(218,642)**	**(217,177)**	**(228,450)**	

Table 20 - DVA Amounts for Disposition

	USoA	Allocator	Balances	Continue Use of Account
LV Variance Account	1550	kWh	0	Yes
Smart Metering Entity Charge Variance Account	1551	# of Customers	(3,251)	Yes
RSVA - Wholesale Market Service Charge	1580	kWh	(39,597)	Yes
RSVA – Wholesale Market Service Charge –Sub Account CBR Class B	1580	kWh	2,681	Yes
RSVA - Retail Transmission Network Charge	1584	kWh	31,388	Yes
RSVA - Retail Transmission Connection Charge	1586	kWh	13,754	Yes
RSVA - Power (excluding Global Adjustment)	1588	kWh	(52,890)	Yes
RSVA - Global Adjustment	1589	Non-RPP kWh	40,762	Yes
Disposition and Recovery/Refund of Regulatory Balances (2020)	1595	%	(29,695)	No
Total of Group 1 Accounts (excluding 1589)			**(77,609)**	
Other Regulatory Assets - Pole Attachment Revenue Variance	1508	kWh	(195,928)	No
Retail Cost Variance Account - Retail	1518	kWh	(20,042)	No
Retail Cost Variance Account - STR	1548	kWh	10,849	No
Other Regulatory - PILS and Tax Variance – CCA Changes	1592	kWh	(23,328)	Yes
Total of Group 2 Accounts			**(228,450)**	
Total of Group 1 Accounts (1550, 1551, 1584, 1586 and 1595)			**12,197**	
Total of Account 1580 and 1588 (not allocated to WMPs)			**(92,487)**	
Balance of Account 1589 Allocated to Non-WMPs			**40,762**	
Group 2 Accounts (including 1592, 1532)			**(228,450)**	

Table 21 - Group 1 Deferral and Variance Account (excluding Global Adj.) Rate Rider

Please indicate the Rate Rider Recovery Period (in months)	12

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	8,867,818	-$ 26,247	- **0.0030**
GENERAL SERVICE < 50 KW	kWh	4,719,852	-$ 12,973	- **0.0027**
GENERAL SERVICE > 50 KW	kW	44,938	-$ 40,258	- **0.8958**
STREET LIGHTING	kW	957	-$ 813	- **0.8497**
		-	$ -	-
		-	$ -	-
		-	$ -	-
		-	$ -	-
		-	$ -	-
		-	$ -	-
		-	$ -	-
		-	$ -	-
		-	$ -	-
		-	$ -	-
		-	$ -	-
		-	$ -	-
		-	$ -	-
		-	$ -	-
		-	$ -	-
		-	$ -	-
Total			**-$ 80,290**	

Table 22 - CBR Class B Rate Rider

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	8,867,818	$ 1,216	**0.0001**
GENERAL SERVICE < 50 KW	kWh	4,719,852	$ 647	**0.0001**
GENERAL SERVICE > 50 KW	kW	13,765	$ 775	**0.0563**
STREET LIGHTING	kW	957	$ 43	**0.0450**
		-	$ -	-
		-	$ -	-
		-	$ -	-
		-	$ -	-
		-	$ -	-
		-	$ -	-
		-	$ -	-
		-	$ -	-
		-	$ -	-
		-	$ -	-
		-	$ -	-
		-	$ -	-
		-	$ -	-
		-	$ -	-
		-	$ -	-
		-	$ -	-
Total			**$ 2,681**	

Table 23 – Global Adjustment Rate Rider

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	88,496	$ 582	**0.0066**
GENERAL SERVICE < 50 KW	kWh	140,480	$ 924	**0.0066**
GENERAL SERVICE > 50 KW	kWh	5,651,069	$ 37,188	**0.0066**
STREET LIGHTING	kWh	314,176	$ 2,067	**0.0066**
	kWh	-	$ -	**-**
	kWh	-	$ -	**-**
	kWh	-	$ -	**-**
	kWh	-	$ -	**-**
	kWh	-	$ -	**-**
	kWh	-	$ -	**-**
	kWh	-	$ -	**-**
	kWh	-	$ -	**-**
	kWh	-	$ -	**-**
	kWh	-	$ -	**-**
	kWh	-	$ -	**-**
	kWh	-	$ -	**-**
	kWh	-	$ -	**-**
	kWh	-	$ -	**-**
	kWh	-	$ -	**-**
	kWh	-	$ -	**-**
Total			**$ 40,762**	

Table 24 – Group 2 Deferral and Variance Account Rate Rider

Rate Rider Calculation for Group 2 Accounts

Please indicate the Rate Rider Recovery Period (in months)		24		
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	1,368	-$ 123,014	**-$ 3.75**
GENERAL SERVICE < 50 KW	kWh	4,719,852	-$ 38,397	**-$ 0.0041**
GENERAL SERVICE > 50 KW	kW	44,938	-$ 50,296	**-$ 0.5596**
STREET LIGHTING	kW	957	-$ 16,742	**-$ 8.7513**
		-	$ -	**$ -**
		-	$ -	**$ -**
		-	$ -	**$ -**
		-	$ -	**$ -**
		-	$ -	**$ -**
		-	$ -	**$ -**
		-	$ -	**$ -**
		-	$ -	**$ -**
		-	$ -	**$ -**
		-	$ -	**$ -**
		-	$ -	**$ -**
		-	$ -	**$ -**
		-	$ -	**$ -**
		-	$ -	**$ -**
		-	$ -	**$ -**
		-	$ -	**$ -**
Total			**-$ 228,450**	

7. Other

7.1 Is the proposed effective date appropriate?

Full Settlement

The Parties agree that Atikokan's new rates should be effective on the same date that Atikokan is able to implement them, subject to May 1, 2025 being the earliest effective date that will be permitted. It is the Parties' expectation that there should be sufficient time for Atikokan to implement rates effective May 1, 2025, should it receive approval of the final updated Rate Order on or before May 19, 2025.

Evidence References

- Exhibit 1 – Administrative Documents

Commitment (IR) Questions

- None

Supporting Parties

All

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

Full Settlement

The Parties agree that Atikokan has responded appropriately to all outstanding OEB directions.

Evidence References

- Exhibit 1 – Administrative Documents

Commitment (IR) Questions

- None

Supporting Parties

All

APPENDICES

Appendix A – Revenue Requirement Workform
Appendix B – 2025 Fixed Asset Continuity Schedule
Appendix C – Capital Expenditure Distribution System Plan
Appendix D – Updated Bill Impacts
Appendix E – Proposed May 1, 2025 Tarriff Sheets

Appendix A – Revenue Requirement Workform

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2025 Filers

Version 1.10

Utility Name	Atikokan Hydro Inc.
Service Territory	
Assigned EB Number	EB-2025-0008
Name and Title	Jennifer Wiens, CEO
Phone Number	807-597-6600
Email Address	jen.wiens@athydro.com
Test Year	2025
Bridge Year	2024
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.

Commencing with 2023 rate applications, 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 2025 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 2025 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)	$ 8,290,346		($89,971)	$ 8,200,375		($32,500)	$ 8,167,875			$ 8,167,875	
	Accumulated Depreciation (average)	($4,816,116)	(5)	($8,339)	$ (4,824,455)		$120,764	$ (4,703,692)			$ (4,703,692)	
	Allowance for Working Capital:											
	Controllable Expenses	$1,369,267		$ -	$ 1,369,267		($5,000)	$ 1,364,267			$ 1,364,267	
	Cost of Power	$3,155,979		($55,520)	$ 3,100,459		$56,803	$ 3,157,262			$ 3,157,262	
	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	$1,622,713		($5,772)	$1,616,941		$3,306	$1,620,247				
	Distribution Revenue at Proposed Rate	$1,738,374		($98,504)	$1,639,871		$2,853	$1,642,723				
	Other Revenue:											
	Specific Service Charges	$4,872		$0	$4,872		$0	$4,872				
	Late Payment Charges	$7,572		$0	$7,572		$0	$7,572				
	Other Distribution Revenue	$4,850		$0	$4,850		$0	$4,850				
	Other Income and Deductions	$155,964		$2,559	$158,523		($1,522)	$157,001				
	Total Revenue Offsets	$173,258	(7)	$2,559	$175,817		($1,522)	$174,295				
	Operating Expenses:											
	OM+A Expenses	$1,340,301		$ -	$ 1,340,301		($5,000)	$1,335,301			$ 1,335,301	
	Depreciation/Amortization	$247,835		($43,055)	$ 204,780		$331	$205,111			$ 205,111	
	Property taxes	$28,966		$ -	$ 28,966			$28,966			$ 28,966	
	Other expenses			$ -								
3	**Taxes/PILs**											
	Taxable Income:											
	Adjustments required to arrive at taxable income	($130,089)	(3)	($155,809)	($285,898)		$1,329	($284,569)				
	Utility Income Taxes and Rates:											
	Income taxes (not grossed up)	$1,269		($1,269)	$ -		$0	$ -				
	Income taxes (grossed up)	$1,445			$ -			$ -				
	Federal tax (%)	3.20%		(3.20%)	0.00%		0.00%	0.00%				
	Provincial tax (%)	9.00%		(9.00%)	0.00%		0.00%	0.00%				
	Income Tax Credits											
4	**Capitalization/Cost of Capital**											
	Capital Structure:											
	Long-term debt Capitalization Ratio (%	56.0%		0.00%	56.0%		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 (%)	6.70%		(2.04%)	4.66%		0.00%	4.66%				
	Short-term debt Cost Rate (%)	6.23%		(1.19%)	5.04%		0.00%	5.04%				
	Common Equity Cost Rate (%)	9.21%		0.04%	9.25%		0.00%	9.25%				
	Prefered Shares Cost Rate (%)	9.21%		0.04%	9.25%		0.00%	9.25%				

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

(1) Some Applicants may have a unique rate as a result of a lead-lag study. The default rate for 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 2025 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)	$8,290,346	($89,971)	$8,200,375	($32,500)	$8,167,875	$ -	$8,167,875
2	Accumulated Depreciation (average)	(2)	($4,816,116)	($8,339)	($4,824,455)	$120,764	($4,703,692)	$ -	($4,703,692)
3	Net Fixed Assets (average)	(2)	$3,474,230	($98,310)	$3,375,920	$88,264	$3,464,184	$ -	$3,464,184
4	Allowance for Working Capital	(1)	$339,393	($4,164)	$335,229	$3,885	$339,115	($339,115)	$ -
5	**Total Rate Base**		$3,813,623	($102,474)	$3,711,150	$92,149	$3,803,298	($339,115)	$3,464,184

(1) Allowance for Working Capital - Derivation

Line No.	Particulars		Initial Application	Adjustments	Interrogatory Responses	Adjustments	Settlement Agreement	Adjustments	Per Board Decision
6	Controllable Expenses		$1,369,267	$ -	$1,369,267	($5,000)	$1,364,267	$ -	$1,364,267
7	Cost of Power		$3,155,979	($55,520)	$3,100,459	$56,803	$3,157,262	$ -	$3,157,262
8	Working Capital Base		$4,525,246	($55,520)	$4,469,726	$51,803	$4,521,529	$ -	$4,521,529
9	Working Capital Rate %	(1)	7.50%	0.00%	7.50%	0.00%	7.50%	-7.50%	0.00%
10	Working Capital Allowance		$339,393	($4,164)	$335,229	$3,885	$339,115	($339,115)	$ -

Notes

(1) Some Applicants may have a unique rate as a result of a lead-lag study. The default rate for 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 2025 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)		$1,738,374	($98,504)	$1,639,871	$2,853	$1,642,723	$ -	$1,642,723
2	Other Revenue	(1)	$173,258	$2,559	$175,817	($1,522)	$174,295	$ -	$174,295
3	Total Operating Revenues		$1,911,632	($95,945)	$1,815,687	$1,331	$1,817,018	$ -	$1,817,018
	Operating Expenses:								
4	OM+A Expenses		$1,340,301	$ -	$1,340,301	($5,000)	$1,335,301	$ -	$1,335,301
5	Depreciation/Amortization		$247,835	($43,055)	$204,780	$331	$205,111	$ -	$205,111
6	Property taxes		$28,966	$ -	$28,966	$ -	$28,966	$ -	$28,966
7	Capital taxes		$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	Other expense		$ -	$ -		$ -		$ -	
9	Subtotal (lines 4 to 8)		$1,617,102	($43,055)	$1,574,047	($4,669)	$1,569,378	$ -	$1,569,378
10	Deemed Interest Expense		$152,591	($48,263)	$104,328	$2,590	$106,918	($9,533)	$97,385
11	Total Expenses (lines 9 to 10)		$1,769,692	($91,318)	$1,678,374	($2,079)	$1,676,296	($9,533)	$1,666,763
12	**Utility income before income taxes**		$141,940	($4,627)	$137,313	$3,409	$140,722	$9,533	$150,255
13	Income taxes (grossed-up)		$1,445	($1,445)	$ -	$ -	$ -	$ -	$ -
14	**Utility net income**		$140,494	($3,181)	$137,313	$3,409	$140,722	$9,533	$150,255

Notes

Other Revenues / Revenue

Note	Other Revenues / Revenue	Initial Application	Adjustments	Interrogatory Responses	Adjustments	Settlement Agreement	Adjustments	Per Board Decision
(1)	Specific Service Charges	$4,872	$ -	$4,872	$ -	$4,872		$4,872
	Late Payment Charges	$7,572	$ -	$7,572	$ -	$7,572		$7,572
	Other Distribution Revenue	$4,850	$ -	$4,850	$ -	$4,850		$4,850
	Other Income and Deductions	$155,964	$2,559	$158,523	($1,522)	$157,001		$157,001
	Total Revenue Offsets	$173,258	$2,559	$175,817	($1,522)	$174,295	$ -	$174,295

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2025 Filers

Taxes/PILs

Line No.	Particulars	Application	Interrogatory Responses	Settlement Agreement	Per Board Decision
	Determination of Taxable Income				
1	Utility net income before taxes	$140,494	$137,313	$140,722	$128,175
2	Adjustments required to arrive at taxable utility income	($130,089)	($285,898)	($284,569)	($284,569)
3	Taxable income	$10,405	($148,585)	($143,847)	($156,394)
	Calculation of Utility income Taxes				
4	Income taxes	$1,269	$ -	$ -	$ -
6	Total taxes	$1,269	$ -	$ -	$ -
7	Gross-up of Income Taxes	$176	$ -	$ -	$ -
8	Grossed-up Income Taxes	$1,445	$ -	$ -	$ -
9	PILs / tax Allowance (Grossed-up Income taxes + Capital taxes)	$1,445	$ -	$ -	$ -
10	Other tax Credits	$ -	$ -	$ -	$ -
	Tax Rates				
11	Federal tax (%)	3.20%	0.00%	0.00%	0.00%
12	Provincial tax (%)	9.00%	0.00%	0.00%	0.00%
13	Total tax rate (%)	12.20%	0.00%	0.00%	0.00%

Notes

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2025 Filers

Capitalization/Cost of Capital

Line No.	Particulars	Capitalization Ratio		Cost Rate	Return
		Initial Application			
		(%)	($)	(%)	($)
	Debt				
1	Long-term Debt	56.00%	$2,135,629	6.70%	$143,087
2	Short-term Debt	4.00%	$152,545	6.23%	$9,504
3	**Total Debt**	60.00%	$2,288,174	6.67%	$152,591
	Equity				
4	Common Equity	40.00%	$1,525,449	9.21%	$140,494
5	Preferred Shares	0.00%	$ -	9.21%	$ -
6	**Total Equity**	40.00%	$1,525,449	9.21%	$140,494
7	**Total**	100.00%	$3,813,623	7.69%	$293,085
		Interrogatory Responses			
		(%)	($)	(%)	($)
	Debt				
1	Long-term Debt	56.00%	$2,078,244	4.66%	$96,846
2	Short-term Debt	4.00%	$148,446	5.04%	$7,482
3	**Total Debt**	60.00%	$2,226,690	4.69%	$104,328
	Equity				
4	Common Equity	40.00%	$1,484,460	9.25%	$137,313
5	Preferred Shares	0.00%	$ -	9.25%	$ -
6	**Total Equity**	40.00%	$1,484,460	9.25%	$137,313
7	**Total**	100.00%	$3,711,150	6.51%	$241,640
		Settlement Agreement			
		(%)	($)	(%)	($)
	Debt				
8	Long-term Debt	56.00%	$2,129,847	4.66%	$99,251
9	Short-term Debt	4.00%	$152,132	5.04%	$7,667
10	**Total Debt**	60.00%	$2,281,979	4.69%	$106,918
	Equity				
11	Common Equity	40.00%	$1,521,319	9.25%	$140,722
12	Preferred Shares	0.00%	$ -	9.25%	$ -
13	**Total Equity**	40.00%	$1,521,319	9.25%	$140,722
14	**Total**	100.00%	$3,803,298	6.51%	$247,640
		Per Board Decision			
		(%)	($)	(%)	($)
	Debt				
8	Long-term Debt	56.00%	$1,939,943	4.66%	$90,401
9	Short-term Debt	4.00%	$138,567	5.04%	$6,984
10	**Total Debt**	60.00%	$2,078,510	4.69%	$97,385
	Equity				
11	Common Equity	40.00%	$1,385,674	9.25%	$128,175
12	Preferred Shares	0.00%	$ -	9.25%	$ -
13	**Total Equity**	40.00%	$1,385,674	9.25%	$128,175
14	**Total**	100.00%	$3,464,184	6.51%	$225,560

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2025 Filers

Revenue Deficiency/Sufficiency

Line No.	Particulars	Initial Application		Interrogatory Responses		Settlement Agreement		Per Board Decision	
		At Current Approved Rates	At Proposed Rates	At Current Approved Rates	At Proposed Rates	At Current Approved Rates	At Proposed Rates	At Current Approved Rates	At Proposed Rates
1	Revenue Deficiency from Below		$115,661		$22,929		$22,476		$396
2	Distribution Revenue	$1,622,713	$1,622,713	$1,616,941	$1,616,941	$1,620,247	$1,620,247	$1,620,247	$1,642,327
3	Other Operating Revenue Offsets - net	$173,258	$173,258	$175,817	$175,817	$174,295	$174,295	$174,295	$174,295
4	**Total Revenue**	$1,795,971	$1,911,632	$1,792,758	$1,815,687	$1,794,542	$1,817,018	$1,794,542	$1,817,018
5	Operating Expenses	$1,617,102	$1,617,102	$1,574,047	$1,574,047	$1,569,378	$1,569,378	$1,569,378	$1,569,378
6	Deemed Interest Expense	$152,591	$152,591	$104,328	$104,328	$106,918	$106,918	$97,385	$97,385
8	**Total Cost and Expenses**	$1,769,692	$1,769,692	$1,678,374	$1,678,374	$1,676,296	$1,676,296	$1,666,763	$1,666,763
9	**Utility Income Before Income Taxes**	$26,279	$141,940	$114,384	$137,313	$118,246	$140,722	$127,779	$150,255
10	Tax Adjustments to Accounting Income per 2013 PILs model	($130,089)	($130,089)	($285,898)	($285,898)	($284,569)	($284,569)	$ -	($284,569)
11	**Taxable Income**	($103,810)	$11,851	($171,514)	($148,585)	($166,323)	($143,847)	$127,779	($134,314)
12	Income Tax Rate	12.20%	12.20%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
13	**Income Tax on Taxable Income**	($12,665)	$1,446	$ -	$ -	$ -	$ -	$ -	$ -
14	**Income Tax Credits**	$ -	$ -	$ -	$ -	$ -	$ -		
15	**Utility Net Income**	$38,944	$140,494	$114,384	$137,313	$118,246	$140,722	$127,779	$150,255
16	**Utility Rate Base**	$3,813,623	$3,813,623	$3,711,150	$3,711,150	$3,803,298	$3,803,298	$3,464,184	$3,464,184
17	Deemed Equity Portion of Rate Base	$1,525,449	$1,525,449	$1,484,460	$1,484,460	$1,521,319	$1,521,319	$1,385,674	$1,385,674
18	Income/(Equity Portion of Rate Base)	2.55%	9.21%	7.71%	9.25%	7.77%	9.25%	9.22%	10.84%
19	Target Return - Equity on Rate Base	9.21%	9.21%	9.25%	9.25%	9.25%	9.25%	9.25%	9.25%
20	Deficiency/Sufficiency in Return on Equity	-6.66%	0.00%	-1.54%	0.00%	-1.48%	0.00%	-0.03%	1.59%
21	Indicated Rate of Return	5.02%	7.69%	5.89%	6.51%	5.92%	6.51%	6.50%	7.15%
22	Requested Rate of Return on Rate Base	7.69%	7.69%	6.51%	6.51%	6.51%	6.51%	6.51%	6.51%
23	Deficiency/Sufficiency in Rate of Return	-2.66%	0.00%	-0.62%	0.00%	-0.59%	0.00%	-0.01%	0.64%
24	Target Return on Equity	$140,494	$140,494	$137,313	$137,313	$140,722	$140,722	$128,175	$128,175
25	Revenue Deficiency/(Sufficiency)	$101,550	$0	$22,929	$0	$22,476	$0	$396	$22,080
26	**Gross Revenue Deficiency/(Sufficiency)**	$115,661 (1)		$22,929 (1)		$22,476 (1)		$396 (1)	

Notes:

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

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2025 Filers

Revenue Requirement

Line No.	Particulars	Application		Interrogatory Responses		Settlement Agreement		Per Board Decision	
1	OM&A Expenses	$1,340,301		$1,340,301		$1,335,301		$1,335,301	
2	Amortization/Depreciation	$247,835		$204,780		$205,111		$205,111	
3	Property Taxes	$28,966		$28,966		$28,966		$28,966	
5	Income Taxes (Grossed up)	$1,445		$ -		$ -		$ -	
6	Other Expenses	$ -							
7	Return								
	Deemed Interest Expense	$152,591		$104,328		$106,918		$97,385	
	Return on Deemed Equity	$140,494		$137,313		$140,722		$128,175	
8	**Service Revenue Requirement (before Revenues)**	$1,911,632		$1,815,687		$1,817,018		$1,794,938	
9	Revenue Offsets	$173,258		$175,817		$174,295		$ -	
10	**Base Revenue Requirement (excluding Tranformer Owership Allowance credit**	$1,738,374		$1,639,870		$1,642,723		$1,794,938	
11	Distribution revenue	$1,738,374		$1,639,871		$1,642,723		$1,642,723	
12	Other revenue	$173,258		$175,817		$174,295		$174,295	
13	**Total revenue**	$1,911,632		$1,815,687		$1,817,018		$1,817,018	
14	**Difference (Total Revenue Less Distribution Revenue Requirement before Revenues)**	$0	(1)	$0	(1)	$0	(1)	$22,080	(1)

Summary Table of Revenue Requirement and Revenue Deficiency/Sufficiency

	Application	Interrogatory Responses	Δ% (2)	Settlement Agreement	Δ% (2)	Per Board Decision	Δ% (2)
Service Revenue Requirement	$1,911,632	$1,815,687	###	$1,817,018	(4.95%)	$1,794,938	(6.10%)
Grossed-Up Revenue Deficiency/(Sufficiency)	$115,661	$22,929	###	$22,476	(80.57%)	$396	(99.66%)
Base Revenue Requirement (to be recovered from Distribution Rates)	$1,738,374	$1,639,870	###	$1,642,723	(5.50%)	$1,794,938	3.25%
Deficiency/(Sufficiency) Associated with Base Revenue Requirement	$115,661	$22,930	###	$22,476	(80.57%)	$ -	(100.00%)

Notes

(1) Line 11 - Line 8
(2) Percentage Change Relative to Initial Application

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2025 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	1,365	8,776,264		1,368	8,853,697		1,368	8,867,818				
2	General Servie Less than 50 kW	232	4,495,158		234	4,712,336		234	4,719,852				
3	General Service greater than 50 kW	15	15,506,375	46,637	15	14,914,371	44,856	15	14,933,631	44,938			
4	Street Lighting	622	341,006	1,058	622	355,073	1,058	622	314,176	957			
5													
6													
7													
8													
9													
10													
11													
12													
13													
14													
15													
16													
17													
18													
19													
20													
	Total		**29,118,803**	**47,695**		**28,835,477**	**45,914**		**28,835,477**	**45,895**			

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 2025 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	$ 653,986	70.83%	$ 1,022,047	56.25%
2	General Servie Less than 50 kW	$ 124,521	13.49%	$ 261,567	14.40%
3	General Service greater than 50 kW	$ 42,459	4.60%	$ 400,832	22.06%
4	Street Lighting	$ 102,412	11.09%	$ 132,571	7.30%
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
	Total	$ 923,378	100.00%	**$ 1,817,017**	100.00%
		Service Revenue Requirement (from Sheet 9)		**$ 1,817,017.99**	

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

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

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

B) Calculated Class Revenues

	Name of Customer Class	Load Forecast (LF) X current approved rates (7B)	LF X current approved rates X (1+d) (7C)	LF X Proposed Rates (7D)	Miscellaneous Revenues (7E)
1	Residential	$ 899,761	$ 912,242	$ 912,242	$ 98,793
2	General Servie Less than 50 kW	$ 276,831	$ 280,671	$ 280,671	$ 25,221
3	General Service greater than 50 kW	$ 305,664	$ 309,904	$ 310,680	$ 30,327
4	Street Lighting	$ 137,990	$ 139,904	$ 139,130	$ 19,955
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
	Total	$ 1,620,246	$ 1,642,723	$ 1,642,723	$ 174,296

(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: 2017	Status Quo Ratios (7C + 7E) / (7A)	Proposed Ratios (7D + 7E) / (7A)	Policy Range
		%	%	%	%
1	Residential	97.95%	98.92%	98.92%	85 - 115
2	General Servie Less than 50 kW	120.00%	116.95%	116.95%	80 - 120
3	General Service greater than 50 kW	86.19%	84.88%	85.07%	80 - 120
4	Street Lighting	120.00%	120.58%	120.00%	80 - 120
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6					
7					
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 2020 with further adjustments to move within the range over two years, the Most Recent Year would be 2023. However, the ratios in 2023 would be equal to those after the adjustment in 2022.

(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		
		2025	2026	2027	
1	Residential	98.92%	98.92%	98.92%	85 - 115
2	General Servie Less than 50 kW	116.95%	116.95%	116.95%	80 - 120
3	General Service greater than 50 kW	85.07%	85.07%	85.07%	80 - 120
4	Street Lighting	120.00%	120.00%	120.00%	80 - 120
5					
6					
7					
8					
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10					
11					
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19					
20					

(11) The applicant should complete Table D if it is applying for approval of a revenue-to-cost ratio in 2025 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 2026 and 2027 Price Cap IR models, as necessary. For 2026 and 2027, enter the planned revenue-to-cost ratios that will be "Change" or "No Change" in 2026 (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'.

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2025 Filers

New Rate Design Policy For Residential Customers

Please complete the following tables.

A Data Inputs (from Sheet 10. Load Forecast)

Test Year Billing Determinants for Residential Class	
Customers	1,368
kWh	8,867,818

Proposed Residential Class Specific Revenue Requirement[1]	$ 912,242.00

Residential Base Rates on Current Tariff	
Monthly Fixed Charge ($)	
Distribution Volumetric Rate ($/kWh)	

B Current Fixed/Variable Split

	Base Rates	Billing Determinants	Revenue	% of Total Revenue
Fixed		1,368		
Variable		8,867,818		
TOTAL	-	-		-

C Calculating Test Year Base Rates

Number of Remaining Rate Design Policy Transition Years[2]	

	Test Year Revenue @ Current F/V Split	Test Year Base Rates @ Current F/V Split	Reconciliation - Test Year Base Rates @ Current F/V Split
Fixed			
Variable			
TOTAL		-	

	New F/V Split	Revenue @ new F/V Split	Final Adjusted Base Rates	Revenue Reconciliation @ Adjusted Rates
Fixed				
Variable				
TOTAL	-	$ -	-	

Checks[3]	
Change in Fixed Rate	
Difference Between Revenues @ Proposed Rates and Class Specific Revenue Requirement	

Notes:

1 The final residential class specific revenue requirement, excluding allocated Miscellaneous Revenues, as shown on Sheet 11. Cost Allocation, should be used (i.e. the revenue requirement after any proposed adjustments to R/C ratios).

2 The distributor should enter the number of years remaining before the transition to fully fixed rates is completed. The change in residential rate design is almost complete and distributors should have either 0 or 1 year remaining. If the distributor has fully transitioned to fixed rates put "0" in cell D40. If the distributor has proposed an additional transition year because the change in the residential rate design will result in the fixed charge increasing by more than $4/year, put "1" in cell D40.

3 Change in fixed rate due to rate design policy should be less than $4. The difference between the proposed class revenue requirement and the revenue at calculated base rates should be minimal (i.e. should be reasonably considered as a rounding error)

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2025 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,

Stage in Process: *Settlement Agreement*

	Customer and Load Forecast					Class Allocated Revenues (From Sheet 11. Cost Allocation and Sheet 12. Residential Rate Design)			Fixed / Variable Splits [2,3] (Percentage to be entered as a fraction between 0 and 1)			Distribution Rates: Monthly Service Charge [2]		Distribution Rates: Volumetric Rate [3]			Revenue Reconciliation		
	Customer Class (From sheet 10. Load Forecast)	Volumetric Charge Determinant	Customers / Connections	kWh	kW or kVA	Total Class Revenue Requirement	Monthly Service Charge	Volumetric	Fixed	Variable	Transformer Ownership Allowance [1] ($)	Rate	No. of decimals	Rate		No. of decimals	MSC Revenues	Volumetric revenues	Distribution Revenues less Transformer Ownership Allowance
1	Residential	kWh	1,368	8,867,818	-	$ 912,242	$ 912,242	$ -	100.00%	0.00%		$55.57	2	$0.0000	/kWh	4	$ 912,237.12	$ -	$ 912,237.12
2	General Servie Less than 50 kW	kWh	234	4,719,852	-	$ 280,671	$ 251,341	$ 29,330	89.55%	10.45%		$89.51		$0.0062	/kWh		$ 251,344.08	$ 29,263.0824	$ 280,607.16
3	General Service greater than 50 kW	kW	15	14,933,631	44,938	$ 310,680	$ 119,143	$ 191,537	38.35%	61.65%	$ 11,187	$661.90		$4.5112	/kW		$ 119,142.00	$ 202,724.3056	$ 310,679.31
4	Street Lighting	kW	622	314,176	957	$ 139,130	$ 126,483	$ 12,647	90.91%	9.09%		$16.95		$13.2218	/kW		$ 126,514.80	$ 12,646.9161	$ 139,161.72
5			-	-	-												$ -	$ -	$ -
6			-	-	-												$ -	$ -	$ -
7			-	-	-												$ -	$ -	$ -
8			-	-	-												$ -	$ -	$ -
9			-	-	-												$ -	$ -	$ -
10			-	-	-												$ -	$ -	$ -
11			-	-	-												$ -	$ -	$ -
12			-	-	-												$ -	$ -	$ -
13			-	-	-												$ -	$ -	$ -
14			-	-	-												$ -	$ -	$ -
15			-	-	-												$ -	$ -	$ -
16			-	-	-												$ -	$ -	$ -
17			-	-	-												$ -	$ -	$ -
18			-	-	-												$ -	$ -	$ -
19			-	-	-												$ -	$ -	$ -
20			-	-	-												$ -	$ -	$ -

Total Transformer Ownership Allowance $ 11,187

Total Distribution Revenues	$	1,642,685.31
Base Revenue Requirement	$	1,642,722.99
Difference	-$	37.68
% Difference		-0.002%

Rates recover revenue requirement

Notes:

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

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

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 2025 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	$ 293,085	7.69%	$ 3,813,623	$ 4,525,246	$ 339,393	$ 247,835	$ 1,445	$ 1,340,301	$ 1,911,632	$ 173,258	$ 1,738,374	$ 115,661

Appendix B – 2025 Fixed Asset Continuity Schedule

Accounting Standard MIFRS
Year **2025**

			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)	$ 49,459			$ 49,459	-$ 48,962	-$ 497		-$ 49,459	-$ 0
CEC	1612	Land Rights (Formally known as Account 1906)	$ -			$ -	$ -			$ -	$ -
N/A	1805	Land	$ -			$ -	$ -			$ -	$ -
47	1808	Buildings	$ -			$ -	$ -			$ -	$ -
13	1810	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -			$ -	$ -			$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ 819,387	$ 15,038		$ 834,425	-$ 335,151	-$ 13,621		-$ 348,773	$ 485,652
47	1825	Storage Battery Equipment	$ -	$ -		$ -	$ -			$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 4,458,617	$ 685,000		$ 5,143,617	-$ 1,952,631	-$ 83,885		-$ 2,036,516	$ 3,107,100
47	1835	Overhead Conductors & Devices	$ -			$ -	$ -			$ -	$ -
47	1840	Underground Conduit	$ -			$ -	$ -			$ -	$ -
47	1845	Underground Conductors & Devices	$ -			$ -	$ -			$ -	$ -
47	1850	Line Transformers	$ 636,429	$ 40,000		$ 676,429	-$ 368,992	-$ 9,457		-$ 378,449	$ 297,980
47	1855	Services (Overhead & Underground)	$ -			$ -	$ -			$ -	$ -
47	1860	Meters	$ 192,637	$ 150,000		$ 342,637	-$ 141,171	-$ 13,651		-$ 154,822	$ 187,815
47	1860	Meters (Smart Meters)	$ 488,652	$ 30,548		$ 519,200	-$ 411,581	-$ 11,231		-$ 422,813	$ 96,388
N/A	1905	Land	$ 15,588			$ 15,588	$ -			$ -	$ 15,588
47	1908	Buildings & Fixtures	$ 703,344			$ 703,344	-$ 470,706	-$ 11,005		-$ 481,710	$ 221,633
13	1910	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 67,579	$ 10,000		$ 77,579	-$ 61,964	-$ 1,583		-$ 63,547	$ 14,032
8	1915	Office Furniture & Equipment (5 years)	$ -			$ -	$ -			$ -	$ -
10	1920	Computer Equipment - Hardware	$ 47,502	$ 5,000		$ 52,502	-$ 38,814	-$ 2,106		-$ 40,920	$ 11,581
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	-$ 0			-$ 0	$ 0			$ 0	$ -
50	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -			$ -	$ -			$ -	$ -
10	1930	Transportation Equipment	$ 976,615	$ 365,000		$ 1,341,615	-$ 707,600	-$ 52,604		-$ 760,204	$ 581,411
8	1935	Stores Equipment	$ -			$ -	$ -			$ -	$ -
8	1940	Tools, Shop & Garage Equipment	$ 166,795	$ 4,000		$ 170,795	-$ 138,172	-$ 5,470		-$ 143,642	$ 27,153
8	1945	Measurement & Testing Equipment	$ -			$ -	$ -			$ -	$ -
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	$ -			$ -	$ -			$ -	$ -
47	1985	Miscellaneous Fixed Assets	$ -			$ -	$ -			$ -	$ -
47	1990	Other Tangible Property	$ -			$ -	$ -			$ -	$ -
47	1995	Contributions & Grants	$ -			$ -	$ -			$ -	$ -
47	2440	Deferred Revenue[5]	-$ 695,521	-$ 823,000		-$ 1,518,521	$ 58,006	$ 33,204		$ 91,210	-$ 1,427,311
	2005	Property Under Finance Lease[7]	$ -			$ -	$ -			$ -	$ -
		Sub-Total	**$ 7,927,082**	**$ 481,586**	**$ -**	**$ 8,408,668**	**-$ 4,617,738**	**-$ 171,907**	**$ -**	**-$ 4,789,645**	**$ 3,619,023**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E for Rate Base Purposes	**$ 7,927,082**	**$ 481,586**	**$ -**	**$ 8,408,668**	**-$ 4,617,738**	**-$ 171,907**	**$ -**	**-$ 4,789,645**	**$ 3,619,023**
		Construction Work In Progress				$ -				$ -	$ -
		Total PP&E	**$ 7,927,082**	**$ 481,586**	**$ -**	**$ 8,408,668**	**-$ 4,617,738**	**-$ 171,907**	**$ -**	**-$ 4,789,645**	**$ 3,619,023**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$ 171,907**			

Less: *Fully Allocated Depreciation*

10		Transportation	Transportation	
8		Stores Equipment	Stores Equipment	
47		Deferred Revenue	Deferred Revenue	$ 33,204
			Net Depreciation	**-$ 205,111**

Appendix 2-AB

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

First year of Forecast Period:

2025

CATEGORY	Forecast Period (planned)				
	2025	2026	2027	2028	2029
	$ '000				
System Access	180,548	15,274	40,000	24,000	12,000
System Renewal	175,038	227,000	162,000	162,000	162,000
System Service	565,000				
General Plant	384,000	34,000	616,000	41,000	79,100
TOTAL EXPENDITURE	1,304,586	276,274	818,000	227,000	253,100
Capital Contributions	- 823,000	- 50,000	- 50,000	- 50,000	- 50,000
NET CAPITAL EXPENDITURES	481,586	226,274	768,000	177,000	203,100
System O&M	$ 619	$ 641	$ 664	$ 688	$ 713

Appendix D – Updated Bill Impacts

Customer Class:	RESIDENTIAL SERVICE CLASSIFICATION
RPP / Non-RPP:	RPP
Consumption	750 kWh
Demand	- kW
Current Loss Factor	1.0945
Proposed/Approved Loss Factor	1.0754

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 54.81	1	$ 54.81	$ 55.57	1	$ 55.57	$ 0.76	1.39%
Distribution Volumetric Rate	$ -	750	$ -	$ -	750	$ -	$ -	
DRP Adjustment		750	$ (13.42)		750	$ (14.18)	$ (0.76)	5.66%
Fixed Rate Riders	$ -	1	$ -	$ (3.37)	1	$ (3.37)	$ (3.37)	
Volumetric Rate Riders	$ -	750	$ -	$ -	750	$ -	$ -	
Sub-Total A (excluding pass through)			**$ 41.39**			**$ 38.02**	**$ (3.37)**	**-8.14%**
Line Losses on Cost of Power	$ 0.0990	71	$ 7.02	$ 0.0990	57	$ 5.60	$ (1.42)	-20.21%
Total Deferral/Variance Account Rate Riders	$ 0.0018	750	$ 1.35	$ (0.0030)	750	$ (2.25)	$ (3.60)	-266.67%
CBR Class B Rate Riders	$ (0.0002)	750	$ (0.15)	$ 0.0001	750	$ 0.08	$ 0.23	-150.00%
GA Rate Riders	$ -	750	$ -	$ -	750	$ -	$ -	
Low Voltage Service Charge	$ -	750	$ -		750	$ -	$ -	
Smart Meter Entity Charge (if applicable)	$ 0.42	1	$ 0.42	$ 0.42	1	$ 0.42	$ -	0.00%
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Volumetric Rate Riders	$ -	750	$ -	$ -	750	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 50.03**			**$ 41.87**	**$ (8.16)**	**-16.32%**
RTSR - Network	$ 0.0101	821	$ 8.29	$ 0.0117	807	$ 9.44	$ 1.15	13.82%
RTSR - Connection and/or Line and Transformation Connection	$ 0.0065	821	$ 5.34	$ 0.0069	807	$ 5.57	$ 0.23	4.30%
Sub-Total C - Delivery (including Sub-Total B)			**$ 63.66**			**$ 56.87**	**$ (6.79)**	**-10.66%**
Wholesale Market Service Charge (WMSC)	$ 0.0045	821	$ 3.69	$ 0.0045	807	$ 3.63	$ (0.06)	-1.75%
Rural and Remote Rate Protection (RRRP)	$ 0.0015	821	$ 1.23	$ 0.0015	807	$ 1.21	$ (0.02)	-1.75%
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
TOU - Off Peak	$ 0.0760	480	$ 36.48	$ 0.0760	480	$ 36.48	$ -	0.00%
TOU - Mid Peak	$ 0.1220	135	$ 16.47	$ 0.1220	135	$ 16.47	$ -	0.00%
TOU - On Peak	$ 0.1580	135	$ 21.33	$ 0.1580	135	$ 21.33	$ -	0.00%
Total Bill on TOU (before Taxes)			**$ 143.11**			**$ 136.24**	**$ (6.87)**	**-4.80%**
HST	13%		$ 18.60	13%		$ 17.71	$ (0.89)	-4.80%
Ontario Electricity Rebate	13.1%		$ (18.75)	13.1%		$ (17.85)	$ 0.90	
Total Bill on TOU			**$ 142.97**			**$ 136.10**	**$ (6.87)**	**-4.80%**

Customer Class:	GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	
RPP / Non-RPP:	RPP	
Consumption	2,000	kWh
Demand	-	kW
Current Loss Factor	1.0945	
Proposed/Approved Loss Factor	1.0754	

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 89.51	1	$ 89.51	$ 89.51	1	$ 89.51	$ -	0.00%
Distribution Volumetric Rate	$ 0.0054	2000	$ 10.80	$ 0.0062	2000	$ 12.40	$ 1.60	14.81%
Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Volumetric Rate Riders	$ -	2000	$ -	$ (0.0037)	2000	$ (7.40)	$ (7.40)	
Sub-Total A (excluding pass through)			$ 100.31			$ 94.51	$ (5.80)	-5.78%
Line Losses on Cost of Power	$ 0.0990	189	$ 18.72	$ 0.0990	151	$ 14.94	$ (3.78)	-20.21%
Total Deferral/Variance Account Rate Riders	$ 0.0021	2,000	$ 4.20	$ (0.0027)	2,000	$ (5.40)	$ (9.60)	-228.57%
CBR Class B Rate Riders	$ (0.0002)	2,000	$ (0.40)	$ 0.0001	2,000	$ 0.20	$ 0.60	-150.00%
GA Rate Riders	$ -	2,000	$ -	$ -	2,000	$ -	$ -	
Low Voltage Service Charge	$ -	2,000	$ -		2,000	$ -	$ -	
Smart Meter Entity Charge (if applicable)	$ 0.42	1	$ 0.42	$ 0.42	1	$ 0.42	$ -	0.00%
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Volumetric Rate Riders		2,000	$ -	$ -	2,000	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)			$ 123.25			$ 104.67	$ (18.58)	-15.08%
RTSR - Network	$ 0.0088	2,189	$ 19.26	$ 0.0102	2,151	$ 21.94	$ 2.67	13.89%
RTSR - Connection and/or Line and Transformation Connection	$ 0.0054	2,189	$ 11.82	$ 0.0057	2,151	$ 12.26	$ 0.44	3.71%
Sub-Total C - Delivery (including Sub-Total B)			$ 154.33			$ 138.86	$ (15.47)	-10.02%
Wholesale Market Service Charge (WMSC)	$ 0.0045	2,189	$ 9.85	$ 0.0045	2,151	$ 9.68	$ (0.17)	-1.75%
Rural and Remote Rate Protection (RRRP)	$ 0.0015	2,189	$ 3.28	$ 0.0015	2,151	$ 3.23	$ (0.06)	-1.75%
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
TOU - Off Peak	$ 0.0760	1,280	$ 97.28	$ 0.0760	1,280	$ 97.28	$ -	0.00%
TOU - Mid Peak	$ 0.1220	360	$ 43.92	$ 0.1220	360	$ 43.92	$ -	0.00%
TOU - On Peak	$ 0.1580	360	$ 56.88	$ 0.1580	360	$ 56.88	$ -	0.00%
Total Bill on TOU (before Taxes)			$ 365.80			$ 350.10	$ (15.70)	-4.29%
HST	13%		$ 47.55	13%		$ 45.51	$ (2.04)	-4.29%
Ontario Electricity Rebate	13.1%		$ (47.92)	13.1%		$ (45.86)	$ 2.06	
Total Bill on TOU			$ 365.43			$ 349.75	$ (15.68)	-4.29%

Customer Class:	GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION	
RPP / Non-RPP:	Non-RPP (Other)	
Consumption	72,337	kWh
Demand	125	kW
Current Loss Factor	1.0945	
Proposed/Approved Loss Factor	1.0754	

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 661.90	1	$ 661.90	$ 661.90	1	$ 661.90	$ -	0.00%
Distribution Volumetric Rate	$ 4.3996	125	$ 549.95	$ 4.5112	125	$ 563.90	$ 13.95	2.54%
Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Volumetric Rate Riders	$ -	125	$ -	$ (0.5110)	125	$ (63.88)	$ (63.88)	
Sub-Total A (excluding pass through)			**$ 1,211.85**			**$ 1,161.93**	**$ (49.93)**	**-4.12%**
Line Losses on Cost of Power	$ -	-	$ -	$ -	-	$ -	$ -	
Total Deferral/Variance Account Rate Riders	$ 0.7509	125	$ 93.86	$ (0.8958)	125	$ (111.98)	$ (205.84)	-219.30%
CBR Class B Rate Riders	$ (0.0524)	125	$ (6.55)	$ 0.0563	125	$ 7.04	$ 13.59	-207.44%
GA Rate Riders	$ 0.0052	72,337	$ 376.15	$ 0.0066	72,337	$ 477.42	$ 101.27	26.92%
Low Voltage Service Charge	$ -	125	$ -		125	$ -	$ -	
Smart Meter Entity Charge (if applicable)	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Volumetric Rate Riders		125	$ -	$ -	125	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 1,675.31**			**$ 1,534.41**	**$ (140.90)**	**-8.41%**
RTSR - Network	$ 3.5988	125	$ 449.85	$ 4.1630	125	$ 520.38	$ 70.53	15.68%
RTSR - Connection and/or Line and Transformation Connection	$ 2.2482	125	$ 281.03	$ 2.3735	125	$ 296.69	$ 15.66	5.57%
Sub-Total C - Delivery (including Sub-Total B)			**$ 2,406.19**			**$ 2,351.47**	**$ (54.72)**	**-2.27%**
Wholesale Market Service Charge (WMSC)	$ 0.0045	79,173	$ 356.28	$ 0.0045	77,791	$ 350.06	$ (6.22)	-1.75%
Rural and Remote Rate Protection (RRRP)	$ 0.0015	79,173	$ 118.76	$ 0.0015	77,791	$ 116.69	$ (2.07)	-1.75%
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
Average IESO Wholesale Market Price	$ 0.0892	79,173	$ 7,059.84	$ 0.0892	77,791	$ 6,936.64	$ (123.20)	-1.75%
Total Bill on Average IESO Wholesale Market Price			**$ 9,941.32**			**$ 9,755.11**	**$ (186.21)**	**-1.87%**
HST	13%		$ 1,292.37	13%		$ 1,268.16	$ (24.21)	-1.87%
Ontario Electricity Rebate	13.1%		$ -	13.1%		$ -		
Total Bill on Average IESO Wholesale Market Price			**$ 11,233.69**			**$ 11,023.28**	**$ (210.41)**	**-1.87%**

Customer Class:	STREET LIGHTING SERVICE CLASSIFICATION
RPP / Non-RPP:	Non-RPP (Other)
Consumption	43,319 kWh
Demand	93 kW
Current Loss Factor	1.0945
Proposed/Approved Loss Factor	1.0754

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 16.95	622	$ 10,542.90	$ 16.95	622	$ 10,542.90	$ -	0.00%
Distribution Volumetric Rate	$ 11.9969	93	$ 1,115.71	$ 13.2218	93	$ 1,229.63	$ 113.92	10.21%
Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Volumetric Rate Riders	$ -	93	$ -	$ (7.7648)	93	$ (722.13)	$ (722.13)	
Sub-Total A (excluding pass through)			$ 11,658.61			$ 11,050.40	$ (608.21)	-5.22%
Line Losses on Cost of Power	$ -	-	$ -	$ -	-	$ -	$ -	
Total Deferral/Variance Account Rate Riders	$ 0.7683	93	$ 71.45	$ 0.8497	93	$ 79.02	$ 7.57	10.59%
CBR Class B Rate Riders	$ (0.0581)	93	$ (5.40)	$ 0.0450	93	$ 4.19	$ 9.59	-177.45%
GA Rate Riders	$ 0.0052	43,319	$ 225.26	$ 0.0066	43,319	$ 285.91	$ 60.65	26.92%
Low Voltage Service Charge	$ -	93	$ -		93	$ -	$ -	
Smart Meter Entity Charge (if applicable)	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Volumetric Rate Riders		93	$ -	$ -	93	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)			$ 11,949.92			$ 11,419.51	$ (530.41)	-4.44%
RTSR - Network	$ 2.7144	93	$ 252.44	$ 3.1399	93	$ 292.01	$ 39.57	15.68%
RTSR - Connection and/or Line and Transformation Connection	$ 1.7379	93	$ 161.62	$ 1.8348	93	$ 170.64	$ 9.01	5.58%
Sub-Total C - Delivery (including Sub-Total B)			$ 12,363.98			$ 11,882.16	$ (481.82)	-3.90%
Wholesale Market Service Charge (WMSC)	$ 0.0045	47,413	$ 213.36	$ 0.0045	46,585	$ 209.63	$ (3.72)	-1.75%
Rural and Remote Rate Protection (RRRP)	$ 0.0015	47,413	$ 71.12	$ 0.0015	46,585	$ 69.88	$ (1.24)	-1.75%
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
Average IESO Wholesale Market Price	$ 0.0892	47,413	$ 4,227.79	$ 0.0892	46,585	$ 4,154.01	$ (73.78)	-1.75%
Total Bill on Average IESO Wholesale Market Price			$ 16,876.49			$ 16,315.93	$ (560.57)	-3.32%
HST	13%		$ 2,193.94	13%		$ 2,121.07	$ (72.87)	-3.32%
Ontario Electricity Rebate	13.1%		$ -	13.1%		$ -		
Total Bill on Average IESO Wholesale Market Price			$ 19,070.44			$ 18,437.00	$ (633.44)	-3.32%

Customer Class:	RESIDENTIAL SERVICE CLASSIFICATION
RPP / Non-RPP:	RPP
Consumption	141 kWh
Demand	- kW
Current Loss Factor	1.0945
Proposed/Approved Loss Factor	1.0754

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 54.81	1	$ 54.81	$ 55.57	1	$ 55.57	$ 0.76	1.39%
Distribution Volumetric Rate	$ -	141	$ -	$ -	141	$ -	$ -	
DRP Adjustment		141	$ (13.42)		141	$ (14.18)	$ (0.76)	5.66%
Fixed Rate Riders	$ -	1	$ -	$ (3.37)	1	$ (3.37)	$ (3.37)	
Volumetric Rate Riders	$ -	141	$ -	$ -	141	$ -	$ -	
Sub-Total A (excluding pass through)			**$ 41.39**			**$ 38.02**	**$ (3.37)**	**-8.14%**
Line Losses on Cost of Power	$ 0.0990	13	$ 1.32	$ 0.0990	11	$ 1.05	$ (0.27)	-20.21%
Total Deferral/Variance Account Rate Riders	$ 0.0018	141	$ 0.25	$ (0.0030)	141	$ (0.42)	$ (0.68)	-266.67%
CBR Class B Rate Riders	$ (0.0002)	141	$ (0.03)	$ 0.0001	141	$ 0.01	$ 0.04	-150.00%
GA Rate Riders	$ -	141	$ -	$ -	141	$ -	$ -	
Low Voltage Service Charge	$ -	141	$ -		141	$ -	$ -	
Smart Meter Entity Charge (if applicable)	$ 0.42	1	$ 0.42	$ 0.42	1	$ 0.42	$ -	0.00%
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Volumetric Rate Riders		141	$ -	$ -	141	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 43.36**			**$ 39.08**	**$ (4.27)**	**-9.85%**
RTSR - Network	$ 0.0101	154	$ 1.56	$ 0.0117	152	$ 1.77	$ 0.22	13.82%
RTSR - Connection and/or Line and Transformation Connection	$ 0.0065	154	$ 1.00	$ 0.0069	152	$ 1.05	$ 0.04	4.30%
Sub-Total C - Delivery (including Sub-Total B)			**$ 45.92**			**$ 41.90**	**$ (4.01)**	**-8.74%**
Wholesale Market Service Charge (WMSC)	$ 0.0045	154	$ 0.69	$ 0.0045	152	$ 0.68	$ (0.01)	-1.75%
Rural and Remote Rate Protection (RRRP)	$ 0.0015	154	$ 0.23	$ 0.0015	152	$ 0.23	$ (0.00)	-1.75%
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
TOU - Off Peak	$ 0.0760	90	$ 6.86	$ 0.0760	90	$ 6.86	$ -	0.00%
TOU - Mid Peak	$ 0.1220	25	$ 3.10	$ 0.1220	25	$ 3.10	$ -	0.00%
TOU - On Peak	$ 0.1580	25	$ 4.01	$ 0.1580	25	$ 4.01	$ -	0.00%
Total Bill on TOU (before Taxes)			**$ 61.06**			**$ 57.03**	**$ (4.03)**	**-6.60%**
HST	13%		$ 7.94	13%		$ 7.41	$ (0.52)	-6.60%
Ontario Electricity Rebate	13.1%		$ (8.00)	13.1%		$ (7.47)	$ 0.53	
Total Bill on TOU			**$ 61.00**			**$ 56.97**	**$ (4.02)**	**-6.60%**

Customer Class:	RESIDENTIAL SERVICE CLASSIFICATION
RPP / Non-RPP:	Non-RPP (Retailer)
Consumption	750 kWh
Demand	- kW
Current Loss Factor	1.0945
Proposed/Approved Loss Factor	1.0754

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 54.81	1	$ 54.81	$ 55.57	1	$ 55.57	$ 0.76	1.39%
Distribution Volumetric Rate	$ -	750	$ -	$ -	750	$ -	$ -	
DRP Adjustment		750	$ (13.42)		750	$ (14.18)	$ (0.76)	5.66%
Fixed Rate Riders	$ -	1	$ -	$ (3.37)	1	$ (3.37)	$ (3.37)	
Volumetric Rate Riders	$ -	750	$ -	$ -	750	$ -	$ -	
Sub-Total A (excluding pass through)			**$ 41.39**			**$ 38.02**	**$ (3.37)**	**-8.14%**
Line Losses on Cost of Power	$ 0.0892	71	$ 6.32	$ 0.0892	57	$ 5.04	$ (1.28)	-20.21%
Total Deferral/Variance Account Rate Riders	$ 0.0018	750	$ 1.35	$ (0.0030)	750	$ (2.25)	$ (3.60)	-266.67%
CBR Class B Rate Riders	$ (0.0002)	750	$ (0.15)	$ 0.0001	750	$ 0.08	$ 0.23	-150.00%
GA Rate Riders	$ 0.0052	750	$ 3.90	$ 0.0066	750	$ 4.95	$ 1.05	26.92%
Low Voltage Service Charge	$ -	750	$ -		750	$ -	$ -	
Smart Meter Entity Charge (if applicable)	$ 0.42	1	$ 0.42	$ 0.42	1	$ 0.42	$ -	0.00%
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Volumetric Rate Riders		750	$ -	$ -	750	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 53.23**			**$ 46.26**	**$ (6.97)**	**-13.10%**
RTSR - Network	$ 0.0101	821	$ 8.29	$ 0.0117	807	$ 9.44	$ 1.15	13.82%
RTSR - Connection and/or Line and Transformation Connection	$ 0.0065	821	$ 5.34	$ 0.0069	807	$ 5.57	$ 0.23	4.30%
Sub-Total C - Delivery (including Sub-Total B)			**$ 66.86**			**$ 61.26**	**$ (5.60)**	**-8.37%**
Wholesale Market Service Charge (WMSC)	$ 0.0045	821	$ 3.69	$ 0.0045	807	$ 3.63	$ (0.06)	-1.75%
Rural and Remote Rate Protection (RRRP)	$ 0.0015	821	$ 1.23	$ 0.0015	807	$ 1.21	$ (0.02)	-1.75%
Standard Supply Service Charge								
Non-RPP Retailer Avg. Price	$ 0.0892	750	$ 66.88	$ 0.0892	750	$ 66.88	$ -	0.00%
Total Bill on Non-RPP Avg. Price			**$ 138.66**			**$ 132.98**	**$ (5.68)**	**-4.10%**
HST	13%		$ 18.03	13%		$ 17.29	$ (0.74)	-4.10%
Ontario Electricity Rebate	13.1%		$ (18.16)	13.1%		$ (17.42)		
Total Bill on Non-RPP Avg. Price			**$ 138.52**			**$ 132.84**	**$ (5.68)**	**-4.10%**

Customer Class:	**RESIDENTIAL SERVICE CLASSIFICATION**
RPP / Non-RPP:	**RPP**
Consumption	**547** kWh
Demand	**-** kW
Current Loss Factor	**1.0945**
Proposed/Approved Loss Factor	**1.0754**

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	$ 54.81	1	$ 54.81	$ 55.57	1	$ 55.57	$ 0.76	1.39%
Distribution Volumetric Rate	$ -	547	$ -	$ -	547	$ -	$ -	
DRP Adjustment		547	$ (13.42)		547	$ (14.18)	$ (0.76)	5.66%
Fixed Rate Riders	$ -	1	$ -	$ (3.37)	1	$ (3.37)	$ (3.37)	
Volumetric Rate Riders	$ -	547	$ -	$ -	547	$ -	$ -	
Sub-Total A (excluding pass through)			**$ 41.39**			**$ 38.02**	**$ (3.37)**	**-8.14%**
Line Losses on Cost of Power	$ 0.0990	52	$ 5.12	$ 0.0990	41	$ 4.08	$ (1.03)	-20.21%
Total Deferral/Variance Account Rate Riders	$ 0.0018	547	$ 0.98	$ (0.0030)	547	$ (1.64)	$ (2.63)	-266.67%
CBR Class B Rate Riders	$ (0.0002)	547	$ (0.11)	$ 0.0001	547	$ 0.05	$ 0.16	-150.00%
GA Rate Riders	$ -	547	$ -	$ -	547	$ -	$ -	
Low Voltage Service Charge	$ -	547	$ -		547	$ -	$ -	
Smart Meter Entity Charge (if applicable)	$ 0.42	1	$ 0.42	$ 0.42	1	$ 0.42	$ -	0.00%
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Volumetric Rate Riders		547	$ -	$ -	547	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 47.80**			**$ 40.94**	**$ (6.87)**	**-14.36%**
RTSR - Network	$ 0.0101	599	$ 6.05	$ 0.0117	588	$ 6.88	$ 0.84	13.82%
RTSR - Connection and/or Line and Transformation Connection	$ 0.0065	599	$ 3.89	$ 0.0069	588	$ 4.06	$ 0.17	4.30%
Sub-Total C - Delivery (including Sub-Total B)			**$ 57.74**			**$ 51.88**	**$ (5.86)**	**-10.15%**
Wholesale Market Service Charge (WMSC)	$ 0.0045	599	$ 2.69	$ 0.0045	588	$ 2.65	$ (0.05)	-1.75%
Rural and Remote Rate Protection (RRRP)	$ 0.0015	599	$ 0.90	$ 0.0015	588	$ 0.88	$ (0.02)	-1.75%
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
TOU - Off Peak	$ 0.0760	350	$ 26.61	$ 0.0760	350	$ 26.61	$ -	0.00%
TOU - Mid Peak	$ 0.1220	98	$ 12.01	$ 0.1220	98	$ 12.01	$ -	0.00%
TOU - On Peak	$ 0.1580	98	$ 15.56	$ 0.1580	98	$ 15.56	$ -	0.00%
Total Bill on TOU (before Taxes)			**$ 115.76**			**$ 109.83**	**$ (5.93)**	**-5.12%**
HST	13%		$ 15.05	13%		$ 14.28	$ (0.77)	-5.12%
Ontario Electricity Rebate	13.1%		$ (15.16)	13.1%		$ (14.39)	$ 0.78	
Total Bill on TOU			**$ 115.64**			**$ 109.72**	**$ (5.92)**	**-5.12%**

Customer Class:	GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	
RPP / Non-RPP:	RPP	
Consumption	3,000	kWh
Demand	-	kW
Current Loss Factor	1.0945	
Proposed/Approved Loss Factor	1.0754	

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 89.51	1	$ 89.51	$ 89.51	1	$ 89.51	$ -	0.00%
Distribution Volumetric Rate	$ 0.0054	3000	$ 16.20	$ 0.0062	3000	$ 18.60	$ 2.40	14.81%
Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Volumetric Rate Riders	$ -	3000	$ -	$ (0.0037)	3000	$ (11.10)	$ (11.10)	
Sub-Total A (excluding pass through)			**$ 105.71**			**$ 97.01**	**$ (8.70)**	**-8.23%**
Line Losses on Cost of Power	$ 0.0990	284	$ 28.08	$ 0.0990	226	$ 22.40	$ (5.67)	-20.21%
Total Deferral/Variance Account Rate Riders	$ 0.0021	3,000	$ 6.30	$ (0.0027)	3,000	$ (8.10)	$ (14.40)	-228.57%
CBR Class B Rate Riders	$ (0.0002)	3,000	$ (0.60)	$ 0.0001	3,000	$ 0.30	$ 0.90	-150.00%
GA Rate Riders	$ -	3,000	$ -	$ -	3,000	$ -	$ -	
Low Voltage Service Charge	$ -	3,000	$ -		3,000	$ -	$ -	
Smart Meter Entity Charge (if applicable)	$ 0.42	1	$ 0.42	$ 0.42	1	$ 0.42	$ -	0.00%
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Volumetric Rate Riders		3,000	$ -	$ -	3,000	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 139.91**			**$ 112.03**	**$ (27.87)**	**-19.92%**
RTSR - Network	$ 0.0088	3,284	$ 28.89	$ 0.0102	3,226	$ 32.91	$ 4.01	13.89%
RTSR - Connection and/or Line and Transformation Connection	$ 0.0054	3,284	$ 17.73	$ 0.0057	3,226	$ 18.39	$ 0.66	3.71%
Sub-Total C - Delivery (including Sub-Total B)			**$ 186.53**			**$ 163.33**	**$ (23.20)**	**-12.44%**
Wholesale Market Service Charge (WMSC)	$ 0.0045	3,284	$ 14.78	$ 0.0045	3,226	$ 14.52	$ (0.26)	-1.75%
Rural and Remote Rate Protection (RRRP)	$ 0.0015	3,284	$ 4.93	$ 0.0015	3,226	$ 4.84	$ (0.09)	-1.75%
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
TOU - Off Peak	$ 0.0760	1,920	$ 145.92	$ 0.0760	1,920	$ 145.92	$ -	0.00%
TOU - Mid Peak	$ 0.1220	540	$ 65.88	$ 0.1220	540	$ 65.88	$ -	0.00%
TOU - On Peak	$ 0.1580	540	$ 85.32	$ 0.1580	540	$ 85.32	$ -	0.00%
Total Bill on TOU (before Taxes)			**$ 503.60**			**$ 480.06**	**$ (23.55)**	**-4.68%**
HST	13%		$ 65.47	13%		$ 62.41	$ (3.06)	-4.68%
Ontario Electricity Rebate	13.1%		$ (65.97)	13.1%		$ (62.89)	$ 3.08	
Total Bill on TOU			**$ 503.10**			**$ 479.58**	**$ (23.52)**	**-4.68%**

Customer Class:	GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	
RPP / Non-RPP:	Non-RPP (Retailer)	
Consumption	2,000	kWh
Demand	-	kW
Current Loss Factor	1.0945	
Proposed/Approved Loss Factor	1.0754	

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 89.51	1	$ 89.51	$ 89.51	1	$ 89.51	$ -	0.00%
Distribution Volumetric Rate	$ 0.0054	2000	$ 10.80	$ 0.0062	2000	$ 12.40	$ 1.60	14.81%
Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Volumetric Rate Riders	$ -	2000	$ -	$ (0.0037)	2000	$ (7.40)	$ (7.40)	
Sub-Total A (excluding pass through)			**$ 100.31**			**$ 94.51**	**$ (5.80)**	**-5.78%**
Line Losses on Cost of Power	$ 0.0892	189	$ 16.85	$ 0.0892	151	$ 13.45	$ (3.41)	-20.21%
Total Deferral/Variance Account Rate Riders	$ 0.0021	2,000	$ 4.20	$ (0.0027)	2,000	$ (5.40)	$ (9.60)	-228.57%
CBR Class B Rate Riders	$ (0.0002)	2,000	$ (0.40)	$ 0.0001	2,000	$ 0.20	$ 0.60	-150.00%
GA Rate Riders	$ 0.0052	2,000	$ 10.40	$ 0.0066	2,000	$ 13.20	$ 2.80	26.92%
Low Voltage Service Charge	$ -	2,000	$ -		2,000	$ -	$ -	
Smart Meter Entity Charge (if applicable)	$ 0.42	1	$ 0.42	$ 0.42	1	$ 0.42	$ -	0.00%
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Volumetric Rate Riders		2,000	$ -	$ -	2,000	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 131.78**			**$ 116.38**	**$ (15.41)**	**-11.69%**
RTSR - Network	$ 0.0088	2,189	$ 19.26	$ 0.0102	2,151	$ 21.94	$ 2.67	13.89%
RTSR - Connection and/or Line and Transformation Connection	$ 0.0054	2,189	$ 11.82	$ 0.0057	2,151	$ 12.26	$ 0.44	3.71%
Sub-Total C - Delivery (including Sub-Total B)			**$ 162.87**			**$ 150.57**	**$ (12.29)**	**-7.55%**
Wholesale Market Service Charge (WMSC)	$ 0.0045	2,189	$ 9.85	$ 0.0045	2,151	$ 9.68	$ (0.17)	-1.75%
Rural and Remote Rate Protection (RRRP)	$ 0.0015	2,189	$ 3.28	$ 0.0015	2,151	$ 3.23	$ (0.06)	-1.75%
Standard Supply Service Charge								
Non-RPP Retailer Avg. Price	$ 0.0892	2,000	$ 178.34	$ 0.0892	2,000	$ 178.34	$ -	0.00%
Total Bill on Non-RPP Avg. Price			**$ 354.34**			**$ 341.82**	**$ (12.52)**	**-3.53%**
HST	13%		$ 46.06	13%		$ 44.44	$ (1.63)	-3.53%
Ontario Electricity Rebate	13.1%		$ (46.42)	13.1%		$ (44.78)		
Total Bill on Non-RPP Avg. Price			**$ 353.99**			**$ 341.48**	**$ (12.51)**	**-3.53%**

Customer Class:	GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION
RPP / Non-RPP:	Non-RPP (Retailer)
Consumption	83,882 kWh
Demand	190 kW
Current Loss Factor	1.0945
Proposed/Approved Loss Factor	1.0754

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 661.90	1	$ 661.90	$ 661.90	1	$ 661.90	$ -	0.00%
Distribution Volumetric Rate	$ 4.3996	190	$ 835.92	$ 4.5112	190	$ 857.13	$ 21.20	2.54%
Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Volumetric Rate Riders	$ -	190	$ -	$ (0.5110)	190	$ (97.09)	$ (97.09)	
Sub-Total A (excluding pass through)			**$ 1,497.82**			**$ 1,421.94**	**$ (75.89)**	**-5.07%**
Line Losses on Cost of Power	$ -	-	$ -	$ -	-	$ -	$ -	
Total Deferral/Variance Account Rate Riders	$ 0.7509	190	$ 142.67	$ (0.8958)	190	$ (170.20)	$ (312.87)	-219.30%
CBR Class B Rate Riders	$ (0.0524)	190	$ (9.96)	$ 0.0563	190	$ 10.70	$ 20.65	-207.44%
GA Rate Riders	$ 0.0052	83,882	$ 436.19	$ 0.0066	83,882	$ 553.62	$ 117.43	26.92%
Low Voltage Service Charge	$ -	190	$ -		190	$ -	$ -	
Smart Meter Entity Charge (if applicable)	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Volumetric Rate Riders		190	$ -	$ -	190	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 2,066.73**			**$ 1,816.05**	**$ (250.67)**	**-12.13%**
RTSR - Network	$ 3.5988	190	$ 683.77	$ 4.1630	190	$ 790.97	$ 107.20	15.68%
RTSR - Connection and/or Line and Transformation Connection	$ 2.2482	190	$ 427.16	$ 2.3735	190	$ 450.97	$ 23.81	5.57%
Sub-Total C - Delivery (including Sub-Total B)			**$ 3,177.66**			**$ 3,057.99**	**$ (119.67)**	**-3.77%**
Wholesale Market Service Charge (WMSC)	$ 0.0045	91,809	$ 413.14	$ 0.0045	90,207	$ 405.93	$ (7.21)	-1.75%
Rural and Remote Rate Protection (RRRP)	$ 0.0015	91,809	$ 137.71	$ 0.0015	90,207	$ 135.31	$ (2.40)	-1.75%
Standard Supply Service Charge								
Non-RPP Retailer Avg. Price	$ 0.0892	91,809	$ 8,186.60	$ 0.0892	90,207	$ 8,043.73	$ (142.86)	-1.75%
Total Bill on Non-RPP Avg. Price			**$ 11,915.10**			**$ 11,642.96**	**$ (272.14)**	**-2.28%**
HST	13%		$ 1,548.96	13%		$ 1,513.58	$ (35.38)	-2.28%
Ontario Electricity Rebate	13.1%		$ -	13.1%		$ -		
Total Bill on Non-RPP Avg. Price			**$ 13,464.07**			**$ 13,156.55**	**$ (307.52)**	**-2.28%**

Customer Class:	**GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION**
RPP / Non-RPP:	**Non-RPP (Other)**
Consumption	**433,900** kWh
Demand	**1,304** kW
Current Loss Factor	**1.0945**
Proposed/Approved Loss Factor	**1.0754**

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 661.90	1	$ 661.90	$ 661.90	1	$ 661.90	$ -	0.00%
Distribution Volumetric Rate	$ 4.3996	1304	$ 5,737.08	$ 4.5112	1304	$ 5,882.60	$ 145.53	2.54%
Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Volumetric Rate Riders	$ -	1304	$ -	$ (0.5110)	1304	$ (666.34)	$ (666.34)	
Sub-Total A (excluding pass through)			$ 6,398.98			$ 5,878.16	$ (520.82)	-8.14%
Line Losses on Cost of Power	$ -	-	$ -	$ -	-	$ -	$ -	
Total Deferral/Variance Account Rate Riders	$ 0.7509	1,304	$ 979.17	$ (0.8958)	1,304	$ (1,168.12)	$ (2,147.30)	-219.30%
CBR Class B Rate Riders	$ (0.0524)	1,304	$ (68.33)	$ 0.0563	1,304	$ 73.42	$ 141.74	-207.44%
GA Rate Riders	$ 0.0052	433,900	$ 2,256.28	$ 0.0066	433,900	$ 2,863.74	$ 607.46	26.92%
Low Voltage Service Charge	$ -	1,304	$ -		1,304	$ -	$ -	
Smart Meter Entity Charge (if applicable)	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Volumetric Rate Riders		1,304	$ -	$ -	1,304	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)			$ 9,566.10			$ 7,647.19	$ (1,918.91)	-20.06%
RTSR - Network	$ 3.8181	1,304	$ 4,978.80	$ 4.4167	1,304	$ 5,759.38	$ 780.57	15.68%
RTSR - Connection and/or Line and Transformation Connection	$ 2.4847	1,304	$ 3,240.05	$ 2.6232	1,304	$ 3,420.65	$ 180.60	5.57%
Sub-Total C - Delivery (including Sub-Total B)			$ 17,784.95			$ 16,827.22	$ (957.73)	-5.39%
Wholesale Market Service Charge (WMSC)	$ 0.0045	474,904	$ 2,137.07	$ 0.0045	466,616	$ 2,099.77	$ (37.29)	-1.75%
Rural and Remote Rate Protection (RRRP)	$ 0.0015	474,904	$ 712.36	$ 0.0015	466,616	$ 699.92	$ (12.43)	-1.75%
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
Average IESO Wholesale Market Price	$ 0.0892	474,904	$ 42,347.15	$ 0.0892	466,616	$ 41,608.15	$ (739.00)	-1.75%
Total Bill on Average IESO Wholesale Market Price			$ 62,981.77			$ 61,235.32	$ (1,746.45)	-2.77%
HST	13%		$ 8,187.63	13%		$ 7,960.59	$ (227.04)	-2.77%
Ontario Electricity Rebate	13.1%		$ -	13.1%		$ -		
Total Bill on Average IESO Wholesale Market Price			$ 71,169.41			$ 69,195.91	$ (1,973.49)	-2.77%

Customer Class:	GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION
RPP / Non-RPP:	Non-RPP (Other)
Consumption	15,348 kWh
Demand	55 kW
Current Loss Factor	1.0945
Proposed/Approved Loss Factor	1.0754

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 661.90	1	$ 661.90	$ 661.90	1	$ 661.90	$ -	0.00%
Distribution Volumetric Rate	$ 4.3996	55	$ 241.98	$ 4.5112	55	$ 248.12	$ 6.14	2.54%
Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Volumetric Rate Riders	$ -	55	$ -	$ (0.5110)	55	$ (28.11)	$ (28.11)	
Sub-Total A (excluding pass through)			**$ 903.88**			**$ 881.91**	**$ (21.97)**	**-2.43%**
Line Losses on Cost of Power	$ -	-	$ -	$ -	-	$ -	$ -	
Total Deferral/Variance Account Rate Riders	$ 0.7509	55	$ 41.30	$ (0.8958)	55	$ (49.27)	$ (90.57)	-219.30%
CBR Class B Rate Riders	$ (0.0524)	55	$ (2.88)	$ 0.0563	55	$ 3.10	$ 5.98	-207.44%
GA Rate Riders	$ 0.0052	15,348	$ 79.81	$ 0.0066	15,348	$ 101.30	$ 21.49	26.92%
Low Voltage Service Charge	$ -	55	$ -		55	$ -	$ -	
Smart Meter Entity Charge (if applicable)	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Volumetric Rate Riders		55	$ -	$ -	55	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 1,022.11**			**$ 937.04**	**$ (85.07)**	**-8.32%**
RTSR - Network	$ 3.5988	55	$ 197.93	$ 4.1630	55	$ 228.97	$ 31.03	15.68%
RTSR - Connection and/or Line and Transformation Connection	$ 2.2482	55	$ 123.65	$ 2.3735	55	$ 130.54	$ 6.89	5.57%
Sub-Total C - Delivery (including Sub-Total B)			**$ 1,343.69**			**$ 1,296.54**	**$ (47.15)**	**-3.51%**
Wholesale Market Service Charge (WMSC)	$ 0.0045	16,798	$ 75.59	$ 0.0045	16,505	$ 74.27	$ (1.32)	-1.75%
Rural and Remote Rate Protection (RRRP)	$ 0.0015	16,798	$ 25.20	$ 0.0015	16,505	$ 24.76	$ (0.44)	-1.75%
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
Average IESO Wholesale Market Price	$ 0.0892	16,798	$ 1,497.91	$ 0.0892	16,505	$ 1,471.77	$ (26.14)	-1.75%
Total Bill on Average IESO Wholesale Market Price			**$ 2,942.64**			**$ 2,867.60**	**$ (75.05)**	**-2.55%**
HST	13%		$ 382.54	13%		$ 372.79	$ (9.76)	-2.55%
Ontario Electricity Rebate	13.1%		$ (385.49)	13.1%		$ (375.66)		
Total Bill on Average IESO Wholesale Market Price			**$ 2,939.70**			**$ 2,864.73**	**$ (74.97)**	**-2.55%**

Customer Class:	GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION
RPP / Non-RPP:	Non-RPP (Other)
Consumption	32,850 kWh
Demand	87 kW
Current Loss Factor	1.0945
Proposed/Approved Loss Factor	1.0754

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 661.90	1	$ 661.90	$ 661.90	1	$ 661.90	$ -	0.00%
Distribution Volumetric Rate	$ 4.3996	87	$ 382.77	$ 4.5112	87	$ 392.47	$ 9.71	2.54%
Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Volumetric Rate Riders	$ -	87	$ -	$ (0.5110)	87	$ (44.46)	$ (44.46)	
Sub-Total A (excluding pass through)			**$ 1,044.67**			**$ 1,009.92**	**$ (34.75)**	**-3.33%**
Line Losses on Cost of Power	$ -	-	$ -	$ -	-	$ -	$ -	
Total Deferral/Variance Account Rate Riders	$ 0.7509	87	$ 65.33	$ (0.8958)	87	$ (77.93)	$ (143.26)	-219.30%
CBR Class B Rate Riders	$ (0.0524)	87	$ (4.56)	$ 0.0563	87	$ 4.90	$ 9.46	-207.44%
GA Rate Riders	$ 0.0052	32,850	$ 170.82	$ 0.0066	32,850	$ 216.81	$ 45.99	26.92%
Low Voltage Service Charge	$ -	87	$ -		87	$ -	$ -	
Smart Meter Entity Charge (if applicable)	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Volumetric Rate Riders		87	$ -	$ -	87	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 1,276.25**			**$ 1,153.69**	**$ (122.56)**	**-9.60%**
RTSR - Network	$ 3.5988	87	$ 313.10	$ 4.1630	87	$ 362.18	$ 49.09	15.68%
RTSR - Connection and/or Line and Transformation Connection	$ 2.2482	87	$ 195.59	$ 2.3735	87	$ 206.49	$ 10.90	5.57%
Sub-Total C - Delivery (including Sub-Total B)			**$ 1,784.94**			**$ 1,722.37**	**$ (62.58)**	**-3.51%**
Wholesale Market Service Charge (WMSC)	$ 0.0045	35,954	$ 161.79	$ 0.0045	35,327	$ 158.97	$ (2.82)	-1.75%
Rural and Remote Rate Protection (RRRP)	$ 0.0015	35,954	$ 53.93	$ 0.0015	35,327	$ 52.99	$ (0.94)	-1.75%
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
Average IESO Wholesale Market Price	$ 0.0892	35,954	$ 3,206.05	$ 0.0892	35,327	$ 3,150.10	$ (55.95)	-1.75%
Total Bill on Average IESO Wholesale Market Price			**$ 5,206.97**			**$ 5,084.68**	**$ (122.29)**	**-2.35%**
HST	13%		$ 676.91	13%		$ 661.01	$ (15.90)	-2.35%
Ontario Electricity Rebate	13.1%		$ -	13.1%		$ -		
Total Bill on Average IESO Wholesale Market Price			**$ 5,883.87**			**$ 5,745.68**	**$ (138.19)**	**-2.35%**

Appendix E – Proposed May 1 2025 Tariff Sheets

Atikokan Hydro Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2025
This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2024-0008

RESIDENTIAL SERVICE CLASSIFICATION

This classification applies to an account taking electricity at 750 volts or less where the electricity is used exclusively in a separate metered living accommodation. Customers shall be residing in single-dwelling units that consist of a detached house or one unit of a semi-detached, duplex, triplex or quadruplex house, with a residential zoning. Separately metered dwellings within a town house complex or apartment building also qualify as residential customers. All customers are single-phase. 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	$	55.57
Rate Rider for Disposition of Group 2 Deferral/Variance Accounts (2025) - effective until April 30, 2027	$	(3.75)
Smart Metering Entity Charge - effective until December 31, 2027	$	0.42
Rate Rider for Disposition of Group 1 Deferral/Variance Accounts (2025) - effective until April 30, 2026	$/kWh	(0.0030)
Rate Rider for Dispositon of Global Adjustment Account (2025) Applicable only for Non-RPP Customers - effective until April 30, 2026	$/kWh	0.0066
Rate Rider for Disposition of CBR Class B Account (2025) - effective until April 30, 2026	$/kWh	0.0001
Retail Transmission Rate - Network Service Rate	$/kWh	0.0117
Retail Transmission Rate - Transformation Connection Service Rate	$/kWh	0.0069

MONTHLY RATES AND CHARGES - Regulatory Component

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

Atikokan Hydro Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2025

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

EB-2024-0008

GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION

This classification applies to a non-residential account taking electricity at 750 volts or less whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW. 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	$	89.51
Smart Metering Entity Charge - effective until December 31, 2027	$	0.42
Distribution Volumetric Rate	$/kWh	0.0062
Rate Rider for Disposition of Group 1 Deferral/Variance Accounts (2025) - effective until April 30, 2026	$/kWh	(0.0027)
Rate Rider for Disposition of Group 2 Deferral/Variance Accounts (2025) - effective until April 30, 2027	$/kWh	(0.0041)
Rate Rider for Dispositon of Global Adjustment Account (2025) Applicable only for Non-RPP Customers - effective until April 30, 2026	$/kWh	0.0066
Rate Rider for Disposition of CBR Class B Account (2025) - effective until April 30, 2026	$/kWh	0.0001
Retail Transmission Rate - Network Service Rate	$/kWh	0.0102
Retail Transmission Rate - Transformation Connection Service Rate	$/kWh	0.0057

MONTHLY RATES AND CHARGES - Regulatory Component

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

Atikokan Hydro Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2025

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EB-2024-0008

GENERAL SERVICE 50 TO 4,999 KW SERVICE CLASSIFICATION

This classification applies to a non residential account whose average monthly maximum demand used for billing purposes is equal to or greater than, or is forecast to be equal to or greater than, 50kW but less than 5,000kW. 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 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 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	$	661.90
Distribution Volumetric Rate	$/kW	4.5112
Rate Rider for Disposition of Group 1 Deferral/Variance Accounts (2025) - effective until April 30, 2026	$/kW	(0.8958)
Rate Rider for Disposition of Group 2 Deferral/Variance Accounts (2025) - effective until April 30, 2027	$/kW	(0.5596)
Rate Rider for Dispositon of Global Adjustment Account (2025) Applicable only for Non-RPP Customers - effective until April 30, 2026	$/kWh	0.0066
Rate Rider for Disposition of CBR Class B Account (2025) - effective until April 30, 2026	$/kW	0.0563

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Retail Transmission Rate - Network Service Rate	$/kW	4.1630
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	2.3735
Retail Transmission Rate - Network Service Rate - Interval Metered	$/kW	4.4167
Retail Transmission Rate - Line and Transformation Connection Service Rate - Interval Metered	$/kW	2.6232

MONTHLY RATES AND CHARGES - Regulatory Component

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

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EB-2024-0008

STREET LIGHTING SERVICE CLASSIFICATION

This classification applies to an account for roadway lighting with a Municipality, Regional Municipality, Ministry of Transportation and private roadway lighting, controlled by photo cells. The consumption for these customers will be based on the calculated connected load times the required lighting times established in the approved Ontario Energy Board street lighting load shape template. 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)	$	16.95
Distribution Volumetric Rate	$/kW	13.2218
Rate Rider for Disposition of Group 1 Deferral/Variance Accounts (2025) - effective until April 30, 2026	$/kW	(0.8497)
Rate Rider for Disposition of Group 2 Deferral/Variance Accounts (2025) - effective until April 30, 2027	$/kW	(8.7513)
Rate Rider for Dispositon of Global Adjustment Account (2025) Applicable only for Non-RPP Customers - effective until April 30, 2026	$/kWh	0.0066
Rate Rider for Disposition of CBR Class B Account (2025) - effective until April 30, 2026	$/kW	0.0450
Retail Transmission Rate - Network Service Rate	$/kW	3.1399
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.8348

MONTHLY RATES AND CHARGES - Regulatory Component

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

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microFIT SERVICE CLASSIFICATION

This classification applies to an electricity generation facility contracted under the Independent Electricity System Operator's microFIT program and connected to the distributor's distribution system. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

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

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

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

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

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	5.00

ALLOWANCES

Transformer Allowance for Ownership - per kW of billing demand/month	$/kW	(0.29)
Primary Metering Allowance for Transformer Losses - applied to measured demand & energy	%	(1.00)

SPECIFIC SERVICE CHARGES

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

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

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

Customer Administration

Returned cheque (plus bank charges)	$	25.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	25.00
Special meter reads	$	25.00

Non-Payment of Account

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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	$	28.00
Reconnection at meter - after regular hours	$	315.00
Reconnection at pole - during regular hours	$	28.00
Reconnection at pole - after regular hours	$	315.00

Other

Specific charge for access to the power poles - $/pole/year	$	39.14
(with the exception of wireless attachments)		39.14

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	$	121.23
Monthly fixed charge, per retailer	$	48.50
Monthly variable charge, per customer, per retailer	$/cust.	1.20
Distributor-consolidated billing monthly charge, per customer, per retailer	$/cust.	0.71
Retailer-consolidated billing monthly credit, per customer, per retailer	$/cust.	(0.71)
Service Transaction Requests (STR)		
Request fee, per request, applied to the requesting party	$	0.61
Processing fee, per request, applied to the requesting party	$	1.20
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)	$	4.85
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)	$	2.42

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.

Atikokan Hydro Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2025

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

EB-2024-0008

Total Loss Factor - Secondary Metered Customer < 5,000 kW	1.0754
Total Loss Factor - Primary Metered Customer < 5,000 kW	1.0648