EXHIBIT 1: APPLICATION OVERVIEW AND ADMINISTRATIVE DOCUMENT

2025 Cost of Service

Atikokan Hydro Inc.

EB-2024-0008

Filed: October 30, 2024

For rates effective: May 1, 2025

2.0 Application

IN THE MATTER OF Ontario Energy Board Act, 1998,

Being Schedule B to the Energy Competition Act, 1998

S.O. 1998, c.15:

AND IN THE MATTER OF an Application by Atikokan Hydro Inc.,

to the Ontario Energy Board for an Order of Orders approving

or fixing just and reasonable rates and other service charges for the

Distribution of electricity as of May 1, 2025

DATED at Atikokan, Ontario this October 30, 2024

ATIKOKAN HYDRO INC.

2025 COST OF SERVICE APPLICATION

For New Rates to be Effective May 1, 2025

2.0.1 General Requirements

Certification

In accordance with the Chapter 2 filing requirements an application filed must include a certification by a senior officer of the Applicant that the evidence filed does not include any personal information, evidence filed is accurate, consistent and complete to the best of their knowledge, and that appropriate processes and internal controls are in place for deferral and variance accounts regardless of whether the accounts are proposed for disposition.

Statement of Certification

I, Jennifer Wiens, CEO, make the following certifications regarding Atikokan Hydro's 2025 Cost of Service Electricity Distribution Rate Application and any evidence filed in support of the application.

1. I confirm that Practice Direction has been followed with respect to Confidential Information and that personal information must be filed in accordance with Rule 9A of the OEB's Rules.
2. I certify to the best of my knowledge, that the evidence filed in support of this application does not include any personal information.
3. I certify that the information filed is accurate, consistent and complete to the best of my knowledge in accordance with Chapter 2 of the Filing Requirements
4. I certify that Atikokan Hydro has appropriate processes and internal controls for the preparation, review and verification of all deferral and variance account balances.

Jennifer Wiens

Jennifer Wiens
CEO/Secretary/Treasurer

Atikokan followed the Chapter 2 OEB Filing Requirements for Electricity Distributors Applications and did not deviate from the requirements to its knowledge. The excel version of the completed 2025 Cost of Service checklist is being filed in conjunction with this application.

Atikokan's application consists of the following Exhibits and live Excel models supporting the evidence presented in the application.

Exhibits:

Exhibit 1: Application Overview and Administrative Documents

Exhibit 2: Rate Base and Distribution System Plan

Exhibit 3: Load and Customer Forecast

Exhibit 4: Operating Expenses

Exhibit 5: Cost of Capital and Capital Structure

Exhibit 6: Revenue Requirement

Exhibit 7: Cost Allocation

Exhibit 8: Rate Design

Exhibit 9: Deferral and Variance Accounts

Models:

Atikokan 2025 COS Checklist

Atikokan 2025 COS Load Forecast Model

Atikokan 2025 COS Cost Allocation Model

Atikokan 2025 COS DVA Continuity Schedule

Atikokan 2025 COS Filing Requirements Chapter 2 Appendices

Atikokan 2025 COS GA Analysis Workform

Atikokan 2025 COS Rev Requirement Workform

Atikokan 2025 COS RTSR Workform

Atikokan 2025 COS Tariff Schedule and Bill Impact Model

Atikokan 2025 COS Test Year Income Tax PILS

Atikokan 2025 COS Load Profiles

PDF – Atikokan Current Tariffs

Materiality Threshold

Atikokan used the materiality threshold of $50,000 for its application per OEB filing requirements where Atikokan is a utility with less than 30,000 customers and a very small utility (defined as utility less than 5,000 customers).

2.1 Exhibit 1: Administrative Overview and Administrative Documents

2.1.1 Table of Contents

2.1.2 Application Summary and Business Plan

Atikokan Hydro, the applicant is referred to as "Atikokan" in this application. Atikokan is requesting an increase to meet its revenue requirement; a revenue deficiency of $115,661 from its existing Board Approved Distribution rates: EB-2023-0052. The revenue deficiency was calculated from taking the 2017 Load Forecast times the existing distribution rates

Atikokan completed its Cost-of-Service Application in accordance with OEB Chapter 2 Filing requirements for Electricity Distribution Rate Applications.

Operations, Maintenance and Administration including Billing and Collecting ("OM&A") costs and programs in this application represent Atikokan's integrated set of asset maintenance and customer activity needs to meet public and employee safety objectives; to comply with the Distribution System Code, environmental requirements and government direction; and to maintain distribution business service quality and reliability at targeted performance levels; ensuring the Town of Atikokan is provided with safe, reliable and affordable electricity. OM&A costs also include providing services to customers connected to Atikokan's distribution system and meeting the requirements of the OEB's Standard Supply Service Code and Retail Settlement Code. This also includes costs to contributing and achieving the new Renewed Regulatory Framework performance outcomes of Customer Focus, Operational Effectiveness and Public Policy Responsiveness. While Atikokan strives to meet or exceed all stakeholder requirements, it all comes at a cost and with a declining customer count it puts added pressure on the remaining customers.

Atikokan has prepared this Distribution System Plan in accordance with the Ontario Energy Board's Chapter 5 Consolidated Distribution System Plan Filing Requirements - For Small Utilities. This distribution system plan covers the historical period of 2017 to 2023, 2024 the bridge year and 2025 to 2029 forecast years. This is Atikokan Hydro's second DSP but first DSP since the OEB's revised 2021 filing requirements for small utilities and Very Small Utilities Working Group (VSUWG) report. This Distribution System Plan is filed in conjunction with Atikokan's Cost of Service Rate Application for rates effective May 1, 2025.

Atikokan has organized the required information using the section headings in the Distribution System Plan Filing Requirements. Investment categories and activities have been grouped into one of the four OEB defined investment categories below, based on the trigger driver of the expenditure:

- ***System access*** investments are modifications (including asset relocation) to a distributor's distribution system a distributor is obligated to perform to provide a customer (including a generator customer) or group of customers with access to electricity services via the distribution system

- ***System renewal*** investments involve replacing and/or refurbishing system assets to extend the original service life of the assets and thereby maintain the ability of the distributor's distribution system to provide customers with electricity services.

- ***System service*** investments are modifications to a distributor's distribution system to ensure the distribution system continues to meet distributor operational objectives while addressing anticipated future customer electricity service requirements

- ***General plant*** investments are modifications, replacements or additions to a distributor's assets that are not part of its distribution system; including land and buildings; tools and equipment; rolling stock and electronic devices and software used to support day to day business and operations activities

Atikokan's goals and mission is to continue to be the distributor of electricity to customers in our service area. The utility will continue to maintain the power of a local distribution company, managing the distribution system in a manner that delivers safe reliable electricity to our customers while being compliant and meeting the changing demands of electricity.

With a lean workforce; both inside (administration) and outside (line crew); the utility must train, retain and succession plan to maintain core and competent staffing levels to provide and respond to the electricity needs of the Town of Atikokan.

Atikokan will continue to leverage economies of scope through shared services and collaboration with both Atikokan's affiliate and the Northwest Group. The utility will continue to collaborate through memberships with the Electricity Distributors Association and Utilities Standard Forum to leverage operational efficiencies.

Atikokan Hydro is committed to:

- efficiently deliver a reliable supply of electrical energy to our customers at competitive distribution rates in the Town of Atikokan; lowest OM&A cost per customer possible; realizing Atikokan's high OM&A expenses per customer
- find efficiencies to control the high OM&A per customer despite the challenges of the utility size and lack of growth
- provide a safe and rewarding work environment for our employees
- provide fair renumeration to employees to keep stability of staffing to meet the needs of reliable power
- assure that future supply is available to meet Atikokan's changing needs and the future of electrification
- be a good corporate citizen within the Town of Atikokan
- foster the Town's strategic plan by supporting economic development, infrastructure and municipal effectiveness and efficiency
- maintaining adequate cash balances, maintaining the utilities financial health and minimizing financial risk
- maintaining debt to equity ratio no greater than the OEB deemed level of 60/40%
- annual investments in distribution assets exceed annual depreciation
- appropriately allocate investments between distribution and non-distribution system general plant expenditures

Atikokan Hydro's long-term vision has been to have Atikokan Hydro's point of power supply from Hydro One Networks Inc. relocated from Moose Lake Transformer Station to the Hydro One owned Mackenzie Transformer Station, with the use of shorter sub-transmission feeder lines. This will foremost improve the overall reliability to our end users. The vision is for improved overall reliability, efficiencies and long-term savings. This vision will be achieved in the test year and a main driver of Atikokan's distribution system plan period.

Atikokan's application and request for rates effective May 1, 2025 includes requests and proposals for approved 2025 Test Year revenue requirement, load forecast, rate base, operations, maintenance, administration including billing and collecting expenses, cost of capital parameters, cost allocation, rate design and disposition of deferral and variance accounts. The next section will summarize the request and proposals with further details outlined in each applicable exhibit.

A: Revenue Requirement

Atikokan is requesting a service revenue requirement of $1,911,632 offset by other revenue of $173,258 for a base revenue requirement of $1,738,374. The 2025 Test Year revenue requirement equates to an increase of 25.9% when compared to the last Cost of Service EB-2016-0056 Approved Revenue Requirement. The proposed revenue requirement, offset by other revenue has a revenue deficiency of $115,661 from Atikokan’s current approved rates and tariffs EB-2023-0006.

Table 1: Proposed Revenue Requirement vs Last Board Approved

Revenue Requirement Input Factors	Last Rebasing Year 2017	2025 Test Year	Variance
Distribution Revenue - Existing Rates		1,622,713	
OM&A	1,097,396	1,340,301	242,905
Depreciation	197,470	247,835	50,365
Property Tax	20,007	28,966	8,959
PILS	12,059	1,445	- 10,614
Return on Debt (interest)	65,654	152,591	86,937
Return on Equity	125,726	140,494	14,768
Total	1,518,312	1,911,632	393,320
Other Revenue (Offsets)	95,770	173,258	77,488
Revenue Deficiency		- 115,661	
Rate Base	3,435,243	3,813,555	378,312
Working Capital Allowance Factor	7.5%	7.5%	0.0%

The main drivers of the revenue requirement change from the 2017 Board Approved revenue are:

- Increase in wages, salaries and benefits
- Outside professional services, including implementation of managed IT service provider
- Increase in metering service provider and maintenance of meters

See Exhibit 6 and the Revenue Requirement Excel Workform for further revenue requirement details.

B: Load Forecast Summary

As outlined in exhibit 3, Atikokan used a multivariate regression analysis consistent with numerous Cost of Service ("COS") applications approved by the Ontario Energy Board ("OEB" or "Board") over the past two decades including Atikokan's 2017 COS. The regression analysis includes actual data to the end of 2023 and relies on statistically valid independent variables to forecast future results. The Load Forecast model was completed by Utilis Consulting.

The table below summarizes the load forecast (customer count and consumption allocators) changes between the 2017 Board Approved load forecast and the 2025 Test Year forecast. While demand has increased both total customer/connection count and kWh consumption have decreased.

Tabel 2: Summary of Load Forecast Change

Customer Rate Class	2017 Board Approved	2025 Test Year	2017 Board Appproved vs. 2025 Test Year	% Change 2017 Board Appproved vs. 2025 Test Year
Residential				
Customers	1,389	1,365	(24)	-1.8%
kWh	9,682,147	8,776,264	(905,883)	-10.3%
General Service < 50 kW				
Customers	228	232	4	1.7%
kWh	5,119,281	4,495,158	(624,123)	-13.9%
General Service 50 to 4999 kW				
Customers	17	15	(2)	-13.3%
kWh	15,044,561	15,506,375	461,814	3.0%
kW	42,599	46,637	4,038	8.7%
Street Lighting				
Customers	625	622	(3)	-0.5%
kWh	461,749	341,006	(120,743)	-35.4%
kW	1,430	1,058	(372)	-35.2%
Total				
Customers /Connections	2,242	2,219	(23)	-1.0%
kWh	30,307,738	29,118,803	(1,188,935)	-4.1%
kW	44,029	47,695	3,666	7.7%

C: Rate Base and DSP

Atikokan is requesting a rate base of $3,813,623 for the 2025 Test year. This is an increase of $378,380 or 11% change when compared to the 2017 Board Approved Rate Base of $3,435,243.

The change in both rate base and gross fixed assets for the 2017 Board Approved year vs the 2025 Test Year is respectively as follows:

Table 3: Proposed Rate Base vs Last Board Approved

2017 Board Approved Versus 2025 Test Year Rate Base	2017 Board Approved	2025 Test Year	Variance $	Variance %
Opening Balance Gross Fixed Assets		7,973,209		
Ending Balance Gross Fixed Assets		8,607,483		
Average Gross Fixed Assets	**6,654,859**	**8,290,346**	**1,635,487**	**24.6%**
Opening Balance Accumulated Depreciation		4,707,562		
Ending Balance Accumulated Depreciation	7,973,209	4,924,670		
Average Accumulated Depreciation	**3,619,240**	**4,816,116**	**1,196,876**	**33.1%**
Average Net Fixed Assets	**3,035,619**	**3,474,230**	**438,611**	**14.4%**
Working Capital	5,328,320	4,525,246	(803,074)	**-15.1%**
Working Capital Allowance	399,624	339,393	(60,231)	**-15.1%**
Total Rate Base	**$3,435,243**	**$3,813,623**	**$378,380**	**11.0%**
Working Capital Factor	**7.5%**	**7.5%**		

The table below on the following page provides a summary of the Rate Base for the period of 2017 through 2025 Test Year. The table shows the trend and change over the years.

Table 4: Summary of Proposed and Historical Rate Base

SUMMARY OF RATE BASE	2017 Board Approved	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Bridge	2025 Test
Opening Balance Gross Fixed Assets		6,440,543	6,685,970	7,149,701	7,293,733	7,287,583	7,373,594	7,459,088	7,610,369	7,973,209
Ending Balance Gross Fixed Assets		6,685,970	7,149,701	7,293,733	7,287,583	7,373,594	7,459,087	7,610,369	7,973,209	8,607,483
Average Gross Fixed Assets	**6,654,859**	**6,563,257**	**6,917,836**	**7,221,717**	**7,290,658**	**7,330,589**	**7,416,341**	**7,534,729**	**7,791,789**	**8,290,346**
Opening Balance Accumulated Depreciation		3,591,059	3,754,436	3,782,245	3,881,436	4,016,416	4,183,760	4,340,993	4,517,452	4,707,562
Ending Balance Accumulated Depreciation		3,754,436	3,782,245	3,881,436	4,016,416	4,183,760	4,340,993	4,517,452	4,707,562	4,924,670
Average Accumulated Depreciation	**3,619,240**	**3,672,748**	**3,768,341**	**3,831,841**	**3,948,926**	**4,100,088**	**4,262,377**	**4,429,223**	**4,612,507**	**4,816,116**
Average Net Fixed Assets	**3,035,619**	**2,890,509**	**3,149,495**	**3,389,877**	**3,341,732**	**3,230,501**	**3,153,964**	**3,105,506**	**3,179,282**	**3,474,230**
Working Capital	5,328,320	5,067,844	4,948,118	4,822,523	4,928,956	4,657,657	4,800,946	4,519,927	4,642,196	4,525,246
Working Capital Allowance	399,624	380,088	371,109	361,689	369,672	349,324	360,071	338,995	348,165	339,393
Total Rate Base	**$3,435,243**	**$3,270,597**	**$3,520,604**	**$3,751,566**	**$3,711,404**	**$3,579,825**	**$3,514,035**	**$3,444,501**	**$3,527,447**	**$3,813,623**

The following table shows the change in capital expenditures for the 2025 Test Year versus the 2017 Board Approved Test Year for the 2017 COS.

Table 5: Proposed Test Year vs Last Board Approved Capital Expenditures

CATEGORY	2017 Board Approved	2025 Test Year
System Access	10,000	165,274
System Renewal	261,740	185,000
System Service	-	200,000
General Plant	304,000	384,000
Total	575,740	934,274
Capital Contributions	-	(300,000)
Net Capital Expenditures	$ 575,740	$ 634,274

Table 6: Proposed DSP vs Last DSP Capital Expenditures

CATEGORY	2017-2021 Planned DSP	2025-2029 Planned DSP	Variance
System Access	125,000	256,548	131,548
System Renewal	816,740	898,000	81,260
System Service	-	200,000	200,000
General Plant	460,000	1,154,100	694,100
Total	1,401,740	2,508,648	1,106,908
Capital Contributions		(300,000)	(300,000)
Net Capital	1,401,740	2,208,648	806,908

See Exhibit 2 and the Distribution System Plan for further details of the proposed rate base.

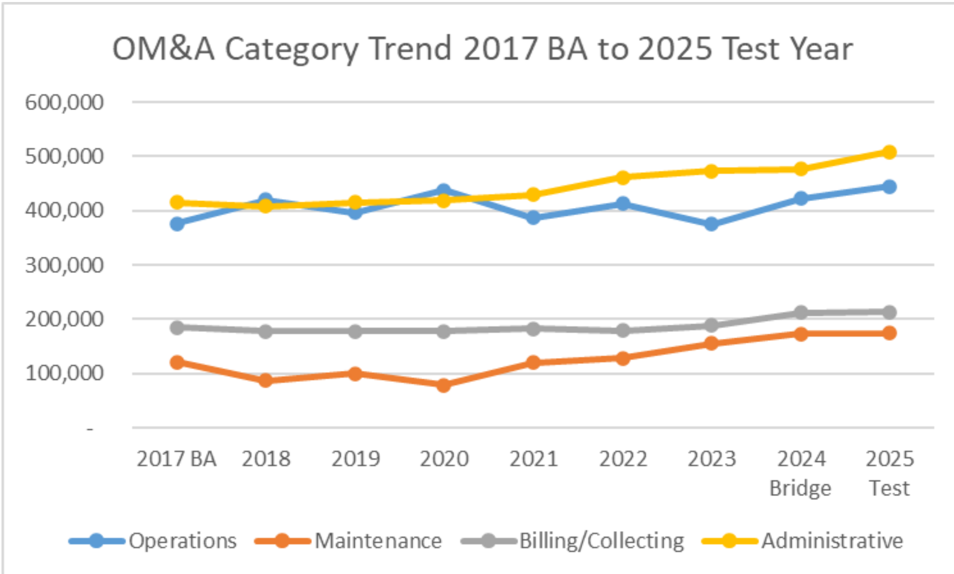
D: Operations, maintenance and administration expense

Atikokan is requesting approval of 2025 Test Year OM&A of $1,340,301. This is a 22.1% increase from the 2017 Board Approved amount of $1,097,396. The change in OM&A Expenses from Board Approved 2017 rebasing Year to the proposed 2025 Test Year is summarized below:

Table 7: Test Year OM&A vs Last Board Approved OM&A

	Last Rebasing Year (2017 Board-Approved)	2025 Test Year	$ Variance	% Variance
Operations	376,877	444,842	67,965	18.0%
Maintenance	120,741	173,697	52,956	43.9%
Billing and Collecting	184,336	213,543	29,207	15.8%
Community Relations	-		-	
Administrative and General	415,442	508,219	92,777	22.3%
Total OM&A Expenses	**1,097,396**	**1,340,301**	**242,905**	**22.1%**

Figure 1: OM&A Trend



The main cost drivers in the change and increase in OM&A include the following:

- Increase in wages, salaries and benefits as per the collective agreement; this impacts all OM&A accounts $140,259
- Outside Professional Services $23,302
  - Increased cost of outside professional services
  - Implementation of managed IT Service Provider
- Increase in metering service provider and maintenance of meters; impacts Maintenance and Billing & Collecting accounts $20,725
- Other immaterial differences less than the Board Approved materiality threshold of $50,000

As determined appropriate by the OEB; Atikokan assumed an inflation rate of 3.6% where expense could not be predicted or unknown. This rate is based on the OEB's letter issued June 20, 2024, providing the 2025 inflation parameters.

See Exhibit 4 for further OM&A details.

E: Cost of Capital

Atikokan Hydro ("Atikokan") followed the Report of the Board on Cost of Capital for Ontario's Regulated Utilities (the "Cost of Capital Report") dated December 11, 2009, to determine its capital structure and relied on the Board's letter titled 2024 Cost of Capital Parameter dated October 31, 2023 for the cost of capital parameters for 2024 Cost-Based Rates.

The OEB determined Cost of Capital parameters are as follows:

ROE	9.21%
Deemed LT Debt rate	4.58%
Deemed ST Debt rate	6.23%

Atikokan acknowledges these Cost of Capital parameters are subject to change and update upon release of the OEB's approved Cost of Capital Parameters for 2025.

Per Filing Requirements, material changes in capital structures are to be disclosed Atikokan confirms it has no material changes in actual or deemed capital structure.

Atikokan has prepared this application with a deemed capital structure of 56% Long Term Debt, 4% Short Term Debt and 40% Equity to comply with the Cost of Capital Report.

Overall, Atikokan is requesting a deemed interest expense of $152,591 and a deemed return on equity of $140,494 for a total regulated return on capital of $293,085 for its 2025 Test Year.

Table 8: Proposed 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

See Exhibit 5 for Cost of Capital further details.

F: Cost Allocation and Rate Design

The Cost Allocation Model is designed to structure rate classes within the Board Policy Range. All classes are within the Board Policy Range except for Streetlighting. Atikokan has proposed to lower the Street Lighting ratio, but it is proposed to still be outside of the upper range. Atikokan is proposing a ratio of 151.88%. This is still outside the range but less than the status quo. To adjust the Streetlight class down to the maximum it would put pressure on the other rate classes. The proposed Streetlight ratio would keep the rates status quo. The rate would not go down nor up. Atikokan is proposing to have the allocation so that the revenue requirement from the class remains. Atikokan believes this to be fair, while the costs are not declining for the customer, the costs remain consistent and will not put unfavorable adjustments to the other classes to offset the required adjustments. To adjust the Street Light ratio the other class were slighted adjusted The Proposed Ratio changes are as follows:

Table 9: Proposed vs Last Board Approved Cost Allocation Ratios

Name of Customer Class	Previously Approved Ratios Most Recent Year: 2017	Status Quo Ratios	Proposed Ratios	Policy Range
Residential	97.95%	96.56%	97.28%	85 - 115
General Service Less Than 50 kW	120.00%	118.68%	118.69%	80 - 120
General Service 50 to 4,999 kW	86.19%	83.20%	83.21%	80 - 120
Street Lighting	120.00%	161.86%	151.88%	80 - 120

Atikokan is not proposing to change the fixed and variable proportions for both the residential and general service < 50 rate classes. Atikokan's residential class has been 100% fixed since 2019. Slight changes are proposed for both the general service > 50 and Streetlight rate class as per the below table.

Table 10: Proposed vs Current Revenue Proportion

Rate Class	Revenue Proportion	Current Proportion	Proposed Proportion	Change
GS > 50 to 4,999 kW	Fixed	36.74%	38.16%	1.42%
GS > 50 to 4,999 kW	Variable	63.26%	61.84%	-1.42%
		100.00%	100.00%	
Street Lighting	Fixed	90.88%	90.92%	0.04%
Street Lighting	Variable	9.12%	9.08%	-0.04%
		100.00%	100.00%	

Atikokan is not proposing to add new customer classes nor changes to existing customer classes. The customer classes approved in Atikokan's last Cost of Service Rate Application EB-2016-0056 remain the same for the 2025 Test year and forward.

Atikokan has no proposed mitigation plans; no customer class has rate impacts equal to or greater than 10%.

G: Deferral and Variance Accounts

Atikokan requests disposition of $(255,720); the sum of Group 1 Deferral and Variance Accounts including Global Adjustment and Group 2 accounts.

Table 11: Proposed DVA Disposition

Disposition Account	Requested Disposition
Group 1 exluding Global Adjustment	(78,095)
Group 1 Global Adjustment	41,018
Group 2	(218,642)
Total	$ (255,720)

The Group 1 Deferral and Variance balance requested to be disposed of includes $(41,018) for Non RPP and $(37,077) RPP.

Atikokan proposes a disposition period of one year for its rate riders except for the group 2 rate rider. Atikokan requests a two-year period for group 2 disposition. Atikokan confirms it has no Atikokan is not requesting any new accounts or sub accounts in this application.

Once final disposition occurs, a few DVA's as listed below will be discontinued. See Exhibit 9 for details.

Account 1508 – Pole Attachment Revenue Variance

Account 1518 – Retail Cost Variance Account - Retail

Account 1548 – Retail Cost Variance Account – STR

H: Bill Impacts

The following billing impacts include the OEB scenarios of a residential customer consuming 750 kWh per month and a general service customer consuming 2,000 kWh per month and having a monthly demand of less than 50 kW per the filing requirements. Atikokan also included bill impact consumption and demand scenarios that are relevant to Atikokan's customers and classes.

As per the filing requirements, commodity and regulatory charges are held constant; the bill impacts are inclusive of the proposed distribution rates, and disposition of deferral and variance accounts in this application.

Table 11: Bill Impact

RATE CLASSES / CATEGORIES *(eg: Residential TOU, Residential Retailer)*	Units	RPP? Non-RPP Retailer? Non-RPP Other?	Current Loss Factor (eg: 1.0351)	Proposed Loss Factor	Consumption (kWh)	Demand kW (if applicable)	RTSR Demand or Demand-Interval?	Billing Determinant Applied to Fixed Charge for Unmetered Classes (e.g. # of devices/connections).
RESIDENTIAL SERVICE CLASSIFICATION	kwh	RPP	1.0945	1.0742	750		CONSUMPTION	1
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	kwh	RPP	1.0945	1.0742	2,000		CONSUMPTION	1
GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION	kw	Non-RPP (Other)	1.0945	1.0742	72,337	125	DEMAND	1
STREET LIGHTING SERVICE CLASSIFICATION	kw	Non-RPP (Other)	1.0945	1.0742	43,319	93	DEMAND	622
RESIDENTIAL SERVICE CLASSIFICATION	kwh	RPP	1.0945	1.0742	141		CONSUMPTION	1
RESIDENTIAL SERVICE CLASSIFICATION	kwh	Non-RPP (Retailer)	1.0945	1.0742	750		CONSUMPTION	1
RESIDENTIAL SERVICE CLASSIFICATION	kwh	RPP	1.0945	1.0742	547		CONSUMPTION	1
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	kwh	RPP	1.0945	1.0742	3,000		CONSUMPTION	1
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	kwh	Non-RPP (Retailer)	1.0945	1.0742	2,000		CONSUMPTION	1
GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION	kw	Non-RPP (Retailer)	1.0945	1.0742	83,882	190	DEMAND	1
GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION	kw	Non-RPP (Other)	1.0945	1.0742	433,900	1,304	EMAND - INTERVA	1
GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION	kw	Non-RPP (Other)	1.0945	1.0742	15,348	55	DEMAND	1
GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION	kw	Non-RPP (Other)	1.0945	1.0742	32,850	87	DEMAND	1
Add additional scenarios if required								
Add additional scenarios if required								
Add additional scenarios if required								
Add additional scenarios if required								
Add additional scenarios if required								
Add additional scenarios if required								
Add additional scenarios if required								

RATE CLASSES / CATEGORIES (eg: Residential TOU, Residential Retailer)	Units	Sub-Total						Total	
		A		B		C		Total Bill	
		$	%	$	%	$	%	$	%
RESIDENTIAL SERVICE CLASSIFICATION - RPP	kwh	$ (3.63)	-9.2%	$ (8.70)	-17.8%	$ (8.55)	-13.7%	$ (8.10)	-5.7%
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION - RPP	kwh	$ (0.82)	-0.8%	$ (14.54)	-11.6%	$ (14.26)	-9.1%	$ (13.58)	-3.7%
GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION - Non-RPP (Other)	kw	$ 19.36	1.6%	$ (77.49)	-4.6%	$ (55.26)	-2.3%	$ (220.19)	-2.0%
STREET LIGHTING SERVICE CLASSIFICATION - Non-RPP (Other)	kw	$ (664.11)	-5.7%	$ (744.99)	-6.2%	$ (732.52)	-5.9%	$ (922.22)	-4.8%
RESIDENTIAL SERVICE CLASSIFICATION - RPP	kwh	$ (3.63)	-9.2%	$ (4.58)	-11.0%	$ (4.56)	-10.3%	$ (4.28)	-7.5%
RESIDENTIAL SERVICE CLASSIFICATION - Non-RPP (Retailer)	kwh	$ (3.63)	-9.2%	$ (7.39)	-14.4%	$ (7.24)	-11.1%	$ (6.87)	-5.4%
RESIDENTIAL SERVICE CLASSIFICATION - RPP	kwh	$ (3.63)	-9.2%	$ (7.33)	-15.7%	$ (7.22)	-12.8%	$ (6.83)	-6.0%
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION - RPP	kwh	$ (4.42)	-4.2%	$ (25.00)	-17.4%	$ (24.58)	-12.9%	$ (23.37)	-4.6%
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION - Non-RPP (Retail	kwh	$ (0.82)	-0.8%	$ (11.04)	-8.4%	$ (10.76)	-6.6%	$ (10.30)	-3.1%
GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION - Non-RPP (Retailer)	kw	$ 4.83	0.3%	$ (176.27)	-8.5%	$ (142.47)	-4.5%	$ (343.92)	-2.6%
GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION - Non-RPP (Other)	kw	$ (244.03)	-3.8%	$ (1,671.30)	-17.5%	$ (1,425.24)	-8.0%	$ (2,556.77)	-3.6%
GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION - Non-RPP (Other)	kw	$ 34.99	3.9%	$ (29.05)	-2.8%	$ (19.26)	-1.4%	$ (45.80)	-1.7%
GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION - Non-RPP (Other)	kw	$ 27.84	2.7%	$ (62.31)	-4.9%	$ (46.83)	-2.6%	$ (124.56)	-2.1%

The proposed bill impacts for a residential customer consuming 750 kWh is $(8.10) whereas a general service < 50 consuming 2000 kWh with demand less than 50 is $(13.58).

Rate Class	Usage		Current Rates Total Bill	2025 Proposed Rates Total Bill	$ Difference	% Difference
	kWh	kW				
RESIDENTIAL SERVICE CLASSIFICATION - RPP	750		$ 141.71	$ 133.61	$ (8.10)	-5.71%
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION - RPP	2,000		$ 367.80	$ 354.21	$ (13.58)	-3.69%
GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION - Non-RPP (Other)	72,337	125	$11,224.74	$ 11,004.55	$ (220.19)	-1.96%
STREET LIGHTING SERVICE CLASSIFICATION - Non-RPP (Other)	43,319	93	$19,065.08	$ (18,142.86)	$ (922.22)	-4.84%
RESIDENTIAL SERVICE CLASSIFICATION - RPP	141		$ 57.20	$ 52.91	$ (4.28)	-7.49%
RESIDENTIAL SERVICE CLASSIFICATION - Non-RPP (Retailer)	750		$ 128.07	$ 121.20	$ (6.87)	-5.36%
RESIDENTIAL SERVICE CLASSIFICATION - RPP	547		$ 113.54	$ 106.71	$ (6.83)	-6.01%
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION - RPP	3,000		$ 509.44	$ 486.08	$ (23.37)	-4.59%
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION - Non-RPP (Retailer)	2,000		$ 331.81	$ 321.51	$ (10.30)	-3.11%
GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION - Non-RPP (Retailer)	83,882	190	$13,453.69	$ 13,109.77	$ (343.92)	-2.56%
GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION - Non-RPP (Other)	493,900	1,304	$71,115.74	$ 68,558.97	$(2,556.77)	-3.60%
GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION - Non-RPP (Other)	15,348	55	$ 2,755.68	$ 2,709.88	$ (45.80)	-1.66%
GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION - Non-RPP (Other)	32,850	87	$ 5,879.81	$ 5,755.25	$ (124.56)	-2.12%

2.1.3 Administration

In accordance with the filing requirements, this section of the application provides information relating to the administration of the application.

Primary Contact Information

Applicant:	Atikokan Hydro
Applicants Address:	117 Gorrie St. PO Box 1480 Atikokan, Ontario P0T 1C0
Applicants Primary Contact:	Jennifer Wiens CEO/Secretary/Treasurer Email: jen.wiens@athydro.com Phone: 807-597-6600 Fax: 807-597-6988

Representation for the Application

Atikokan's Load Forecast in conjunction with Exhibit 3 was completed by Utilis Consulting.

Confirmation of Internet Address

Atikokan's website address is www.athydro.com

Atikokan Hydro has a social media account; Atikokan Hydro Facebook account: www.facebook/AtikokanHydroInc

Statement of Publication

Atikokan will follow the OEB's instructions regarding the publication of the Notice in relation to this application, Atikokan proposes to publish the Notice of Application or other notices as directed by the OEB in our local weekly newspaper the Atikokan Progress.

Atikokan confirms its website is www.athydro.com and that the application and related materials will be posted its website and available for viewing.

The application will also be available on the Boards website at www.ontarioenergyboard.ca under Board File Number EB-2024-0008.

Form for Hearing Requested

Atikokan request that this Application be disposed of by way of a written hearing to minimize costs associated.

Proposed Effective Date of Rate Order

Atikokan requests its Rate Order effective May 1, 2025. In the event the Board is unable to provide a Decision and Order in this application for implementation by the applicant as of May 1, 2025, Atikokan requests that the Board declare its current rates interim effective May 1, 2025.

Changes in Methodologies

Atikokan has not made any changes in methodologies used in previous applications.

Board Directives from Previous Decisions and Orders

Update of Load Profile

In Atikokan's prior Cost of Service Application, EB-2016-0052, the modeled weather normalized data was based on the Hydro One load profiles by rate classification provided for the initial cost allocation study and for the coincident and non-coincident peaks for each classification. The filing requirements were updated in 2017 to require distributors to update all classes' load profiles to produce updated demand allocators. This is Atikokan's first applicable filing since the filing requirements were updated requiring updated load profiles.

To achieve the updated load profiles and demand allocators, the historical average method was used to determine the demand allocators, utilizing the most recent 3 years of historical data, 2021, 2022 and 2023. Atikokan consulted Utilis Consulting to complete the load profile and demand allocators.

Loss Factor

Atikokan has corresponded with Board Staff over Atikokan's high loss factor over the years. In Atikokan's correspondence to the OEB for 2024 IRM; EB-2023-0006, Atikokan commented "Atikokan is scheduled to file its 2025 Cost of Service; loss factor changes is part of the filing requirements expected to be addressed if applicable. As applicable, Atikokan will request Loss Factor changes as part of its application." Atikokan is addressing its loss factor in this application and proposes a reduction from the previously approved 1.0945 to 1.0742. See Exhibit 8 for further details.

Conditions of Service

Atikokan has not proposed any changes to its condition of service as part of this application.

The conditions have not changed since last 2017 Cost of Service filing. Atikokan's current Conditions of Service (January 2010) are available on our website and shared upon request. Atikokan confirms we have not made OEB unapproved changes in our Conditions of Service.

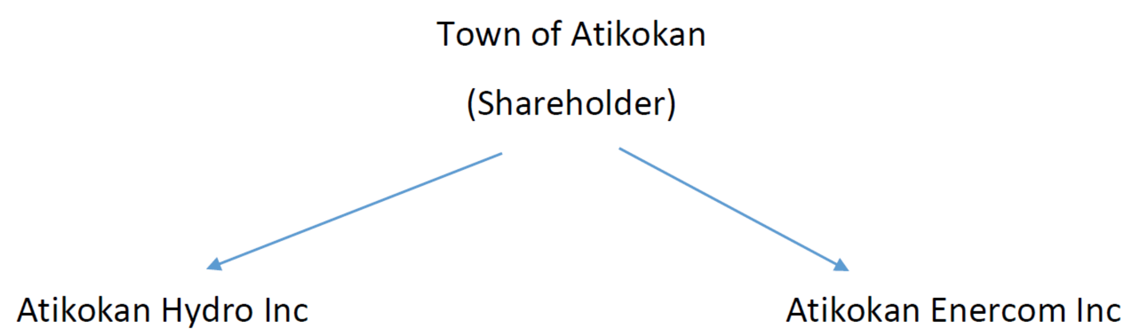
Atikokan will review its conditions of service for required update and changes but outside of this application at a future date.

Corporate Profile and Organizational Structure

The following figure 2 represents the corporate entities relationship. There are no additional entities. The Town of Atikokan solely owns both Atikokan Hydro and its affiliate Atikokan Enercom. Atikokan Hydro has a shared service agreement with its affiliate, Atikokan Enercom Inc, also wholly owned by shareholder, The Town of Atikokan. The shared service agreement between the entities follows the Affiliate Relationship Code. Both Atikokan Hydro and Atikokan Enercom have separate Board of Directors, where one third of the board differs from one another.

Atikokan Hydro has been incorporated since 2000 in accordance with Section 142 of the Electricity Act, 1998.

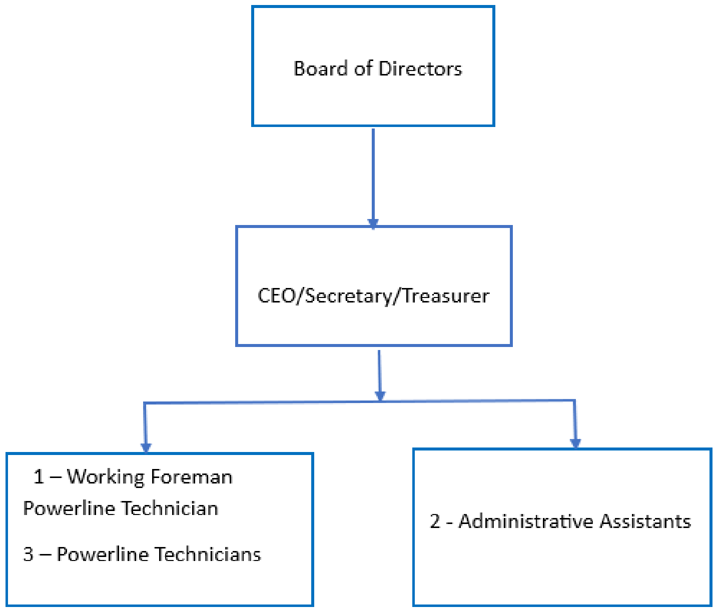
Figure 2: Corporate Structure



There are no planned changes in both corporate or organization structure including changes in legal organization or control. Atikokan Hydro is managed by its Board of Directors appointed by the Town of Atikokan.

Atikokan's internal organization structure is demonstrated below.

Figure 3: Organization Structure



Specific Approvals

Atikokan is not seeking any new rate classifications nor eliminating rate classifications. Atikokan is requesting an increase to meet its revenue requirement. OM&A costs and programs in this application represent Atikokan's integrated set of asset maintenance and customer activity needs to meet public and employee safety objectives; to comply with the Distribution System Code, environmental requirements and government direction; and to maintain distribution business service quality and reliability at targeted performance levels; ensuring the Town of Atikokan is provided with safe, reliable and affordable electricity. OM&A costs also include providing services to customers connected to Atikokan's distribution system and meeting the requirements of the OEB's Standard Supply Service Code and Retail Settlement Code. This also includes costs to contributing and achieving the new Renewed Regulatory Framework performance outcomes of Customer Focus, Operational Effectiveness and Public Policy Responsiveness. While Atikokan strives to meet or exceed all stakeholder requirements, it all comes at a cost and with a declining customer count it puts added pressure on the remaining customers.

A list of specific approvals requested are as follows:

- Approval to charge distribution rates effective May 1, 2025 to recover a base revenue requirement of $1,738,374 which includes a revenue deficiency of $115,661. The schedule of proposed rates is set out in Exhibit 8.
- Approval of test year Operations, Maintenance, Billing & Collecting, and Administration expenses, property tax, payment in lieu of taxes as per Exhibit 4.
- Approval of the 2025 capital expenditures as supported by the Distribution System Plan outlined in Exhibit 2
- Approval to adjust the Retail Transmission Rates - Network and Connection as detailed in Exhibit 8
- Approval of the proposed loss factor as detailed in Exhibit 8.
- Approval of capital structure, cost of capital parameters and deemed return on equity and debt as per Exhibit 5.
- Approval to continue to charge Wholesale Market Services, Capacity Based Recovery and Rural Rate Protection Charges.
- Approval to continue the Specific Service Charges and Transformer Allowance as previously approved by the OEB and detailed in Exhibit 8.
- Approval of the rate riders for a one year disposition of the Group 1 and two year disposition of Group 2 Rate Riders proposed and detailed in Exhibit 9.
- Approval and acceptance of Atikokan’s Demand Profile to determine the Non-Coincident Peak and Coincident Peak Demand Allocators as applied in the Cost Allocation model and described in Exhibit 7.
- Approval of Cost Allocation as detailed in Exhibit 7.
- Other items or amounts that may be requested by Atikokan during this proceeding.

2.1.4 Distribution System Overview

Atikokan Hydro's service area covers 380 sq. km servicing approximately 1600 customers. Atikokan's considered to be in an urban distribution service area, as listed in on OEB Yearbook. However, if looking at the definitions of both Urban and Rural; Atikokan technically fits more with the description of rural based on population per Km of line.

Atikokan is located off Highway 11, between Fort Frances and Thunder Bay. The outlying service territory around Atikokan is serviced by Hydro One Networks Inc transmission assets. Fort Frances Power Corp and Synergy North are neighbouring LDCs. Fort Frances is 150 km from Atikokan whereas Thunder Bay is 209 km.

Atikokan is not a host distributor nor embedded.

Atikokan confirms it has no transmission or high voltage assets.

Electricity is transmitted from Hydro One's Moose Lake TS to Atikokan's two 44KV sub transmission feeders named the 3m2 and the 3m3. The two circuits create a redundancy of supply to the town. The circuits are paralleled in that the open point can be variable. The two lines create greater reliability as an alternative electricity source in event one line is down. Atikokan Hydro has three substations in the most densely populated customer area that distributes the electricity at 8320/4800 volts.

The following map below illustrates an overview of the Atikokan Hydro distribution area and that it extends outside of the town limits up to transmitter Hydro One Networks Inc at it's Moose Lake Transformer Station. The lines in the map illustrate Atikokan Hydro's sub-transmission 44 kV feeders named the 3M2 and 3M3. Not portrayed in the illustration is the distribution feeders within the town limits. The two sub-transmission lines transmitting power to town have posed to be challenging; the terrain is rough, and access to the structures is limited. Atikokan Hydro does not have the internal resources, often utilizing outside contractors to repair noted line inspection deficiencies on these lines increasing the costs to maintain.

Figure 4: Service Area

2.1.5 Customer Engagement

Ongoing customer engagement

Atikokan Hydro has an office accessible to the public 5 days a week. This gives customers an opportunity to make their billing inquiries, pay their hydro bill, setup payment arrangements, setup an account, request disconnection or reconnection of hydro, request a service order for trees, report concerns or any other inquiries in person. Alternatively, customers can phone, fax, complete a web form or email for assistance. Customers can also use Atikokan's online interactive portal to analyze bills, view energy use, choose and change energy price plan and subscribe to paperless billing.

Atikokan has a Facebook social media page it posts energy saving tips, industry news, safety tips like Ontario One Call before you dig rules, share media posts from Electrical Safety Authority, share available financial assistance programs like LEAP and OESP.

Atikokan is supportive of Financial Assistance Programs like LEAP and OESP and helps assist applicants with program applications.

The utility is supportive of community events like the Christmas Parade and holiday lighting on downtown streetlights.

Atikokan engages with its customers in advance with planned outage notifications by way of direct door delivery notices to inform customers about specific outage details (date and planned duration of the outage) and reasons for the outage.

Atikokan completes the biannual electrical safety awareness survey. The latest survey completed March of 2024 indicated an Index Score of 87% reflecting many have good knowledge or have received some information pertaining to electrical safety including contact to overhead wires as an example. This index will be reported on Atikokan's 2023 scorecard once finalized. This index is an improvement from the previous 82% reported on the 2022 scorecard from the 2022 bi-annual survey. Atikokan utilized a third party to complete the survey and used a hybrid approach of both telephone surveys and online surveys.

Customer Satisfaction Survey Results

The Ontario Energy Board requires distributors to measure and report customer satisfaction. As a measure to obtain feedback, Atikokan has had a portion of the bill dedicated to customer ability to express their satisfaction or dissatisfaction with Atikokan or make comments. Atikokan has not had customers respond to this feature and for this reason has interpreted this as favorable.

Atikokan Hydro ran a customer satisfaction survey fall of 2023. The survey was a hybrid approach with the option to complete the survey online or through a paper-based survey. Overall, of the customers that participated, results showed that most respondents are 'very satisfied' with the services provided by Atikokan Hydro. Atikokan was pleased with the results. One hundred and nine surveys were returned. This represents less than ten percent of residential customers. Survey results have been included in the Appendix of Atikokan's Distribution System Plan. Atikokan will continue to strive to satisfy its customers with performance and reliability at the lowest cost and work towards continuous improvement taking back the feedback and comments from the survey.

Application Specific Customer Engagement

Atikokan used responses from the customer satisfaction survey, completed fall of 2023, for preparation of this application. For example, in consideration of electrification, Atikokan asked if respondents plan on purchasing an electric vehicle and plan on installing a small, scaled generation system such as solar in the next 5 years?

In support of Atikokan's Distribution System Plan and a main component being the change in Atikokan's connection point from its upstream transmitter, Atikokan asked if respondents agreed with the project. Survey results have been included in the Appendix of Atikokan's Distribution System Plan. Atikokan believes it is on course with the need and demands of its customers.

Based on the feedback to the questions and interactions to date, Atikokan feels the utilities decisions and plans are meeting the needs and priorities of its customers.

2.1.6 Performance Measurement

Under the renewed regulatory framework (RRF), a distributor is expected to continuously improve its understanding of the needs and expectations of its customers and its delivery of services. To facilities performance monitoring and benchmarking of distributors the OEB uses a scorecard approach.

The Scorecard Approach, issued on March 5, 2014, details the scorecard measures which the Board uses in order to monitor and assess a distributor's effectiveness and improvement in achieving the four performance outcomes – Customer Focus, Operational Effectiveness, Public Policy Responsiveness and Financial Performance – and to facilitate distributor benchmarking. The Board has set industry targets for New Residential/Small Business Services Connected on Time, Scheduled Appointment Met on Time, Telephone Calls Answered on Time, and Billing Accuracy. Other metrics such as Level of Compliance with O. Reg 22/04, number of public incidents, SAID and SAIFI have a trend indicator to identify how each LDC is trending in comparison to previous years.

Atikokan Hydro is continually working to improve performance and is motivated by the OEB's distributor benchmarks and Service Quality Requirements within Section 7 of the Distribution System Code but also driven by the paybacks to Atikokan Hydro's local ratepayers (consumers) from improved performance. The OEB Scorecard is modelled to monitor performance and as such Atikokan utilizes it as a benchmark.

Atikokan's most recent scorecard is posted on its website: scorecard - Atikokan Hydro Inc

Along with the scorecard, the OEB publishes a report each year on the benchmarking of electricity distributor cost performance. An economic model is used to generate efficiency rankings of each distributor to one of five groups [cohorts] based on annul benchmarked cost performance.

The Cohort and definitions are as follows:

- Cohort 1 (Actual costs are more than 25% *below* predicted costs):
- Cohort 2 (Actual costs are between 10% and 25% *below* predicted costs):
- Cohort 3 (Actual costs are within 10% of predicted costs):
- Cohort 4 (Actual costs are between 10% and 25% *above* predicted costs)
- Cohort 5 (Actual costs are more than 25% *above* predicted costs)

It is Atikokan's objective to fall within Cohort 3 at the very least. Historical results show Atikokan has successfully fell within Cohort 3 since 2019, an improvement from Cohort 4 in 2018. The table also shows the IRM application increases approved each year.

Table 12: Approved IRM increases and Assigned Cohort

	2018	2019	2020	2021	2022	2023	Bridge 2024
IRM Increase	0.90%	1.05%	1.55%	1.90%	3.00%	3.40%	4.50%
Cohort Group	4	3	3	3	3	3	TBD

In addition to the scorecard and cohort cost performance, the Activity and Program based Benchmarking (APB) is an ongoing measure to encourage continuous improvement by regulated utilities and increase regulatory efficiency. The APB includes ten programs. The programs and their basis for calculation are in the below table.

Table 13: APB Programs and Calculation

Program	Numerator	Denominator
1. Billing O&M	USoA [5315]	[Number of customers]
2. Metering O&M	USoA [5065 + 5175 + 5310]	[Number of customers]
3. Vegetation Management O&M	USoA [5135]	[Total poles in system]
4. Lines O&M	USoA [5020 + 5025 + 5040 + 5045 + 5090 + 5095 + 5125 + 5130 + 5145 + 5150 + 5155]	[Circuit km of primary line]
5. Stations O&M	USoA [5016 + 5017 + 5114]	[Station transformer MVA / Number of stations]
6. Poles, Towers O&M	USoA [5120]	[Total poles in system]
7. Stations CAPEX	USoA [1820] Capital Additions	[Station transformer MVA / Number of stations]
8. Poles, Towers CAPEX	USoA [1830] Capital Additions	[Number of poles installed]
9. Line Transformers CAPEX	USoA [1850] Capital Additions	[Number of transformers installed]
10. Meters CAPEX	USoA [1860] Capital Additions	[Number of customers]

The following tables are data sourced from the Pacific Economics Group (PEG) APB 2022 report. Atikokan compared itself to other very small utilities (VSU) and the industry distributor average for each of the programs. In most of the programs, Atikokan's spend and impacts per customer are greater than the distributor average and higher amongst the VSU. The comparison's show Atikokan has efficiencies and improvements to gain. However, Atikokan's costs are mainly nondiscretionary and for this reason out of the utilities control and have a greater per customer impact with a smaller customer base compared to most of its neighboring and other LDCs.

Billing O&M

Atikokan's Billing O&M spend is less than the distributor average but the cost per customer is higher than the distributor average of $35.80 by more than double. Atikokan completes its billing internally. In the past, Atikokan compared the cost of printing the bills externally, but it was more cost effective to continue our current practices of completing billing in house from preparing, verifying and printing and mailing the bills. While Atikokan has room to improve when compared to the distributor average of all LDCs, from the table below Atikokan is within the range of that with other small utilities. Atikokan is mindful of its billing costs but would like to note it is difficult to achieve lower costs with a smaller customer base.

Table 14: Billing O&M Indexes

Distributor	Table 1: Unit Cost Indexes by Distributor: Billing O&M											
	USoA [5315]											
	Cost ($1,000)						Unit Cost ($/Customer)					
	2018	2019	2020	2021	2022	Average	2018	2019	2020	2021	2022	Average
Chapleau Public Utilities Corporation	72.0	81.4	87.0	77.8	64.0	76.4	59.58	66.64	71.14	63.55	52.30	62.64
Wellington North Power Inc.	108.4	110.1	102.7	107.8	120.6	109.9	28.49	28.73	26.60	27.34	29.77	28.19
Atikokan Hydro Inc.	137.3	138.3	143.2	142.8	143.7	141.0	83.93	84.88	88.00	88.17	88.73	86.74
Hydro 2000 Inc.	138.4	156.7	139.5	174.9	187.6	159.4	109.65	125.97	109.55	138.44	147.96	126.31
Fort Frances Power Corporation	183.2	166.9	159.2	170.3	175.2	171.0	48.93	44.24	42.34	45.55	46.79	45.57
Sioux Lookout Hydro Inc.	191.6	199.3	202.0	190.1	195.2	195.6	67.49	69.98	71.10	65.47	66.96	68.20
Cooperative Hydro Embrun Inc.	190.0	205.3	200.8	208.4	205.2	202.0	82.43	86.79	83.37	85.25	79.69	83.51
Hearst Power Distribution Company Limite	201.5	206.5	229.3	240.5	217.9	219.2	74.70	76.50	86.25	88.58	80.12	81.23
Renfrew Hydro Inc.	293.2	312.1	312.0	346.6	353.8	323.6	68.01	72.16	71.82	79.42	80.71	74.42
Distributor Average						2,597.8						35.8

Metering O&M

Atikokan's metering costs are higher than the distributor average. Given this measures unit cost is driven by number of customers it is difficult to achieve lower costs. The costs in this index are driven both by variable and fixed expenses. Activities like meter replacements due to failed meters are variable and will vary dependent on failure rates; cost of advanced metering infrastructure is fixed in that most of the cost is fixed no matter the total customers served. Again, most of this measure its out of Atikokan's control but the utility can continue to be mindful.

Table 15: Metering O&M Indexes

Distributor	Table 2: Unit Cost Indexes by Distributor: Metering O&M											
	USoA [5065 + 5175 + 5310]											
	Cost ($1,000)						Unit Cost ($/Customer)					
	2018	2019	2020	2021	2022	Average	2018	2019	2020	2021	2022	Average
Cooperative Hydro Embrun Inc.	-	12.0	6.5	3.3	2.6	6.1	-	5.06	2.69	1.35	1.01	2.53
Hydro 2000 Inc.	15.6	8.1	7.6	2.3	3.2	7.4	12.38	6.49	5.94	1.85	2.50	5.83
Hearst Power Distribution Company Limited	38.9	34.4	21.1	40.8	40.0	35.0	14.41	12.75	7.92	15.02	14.72	12.96
Chapleau Public Utilities Corporation	41.6	41.9	42.9	45.0	6.6	35.6	34.45	34.31	35.05	36.78	5.41	29.20
Renfrew Hydro Inc.	36.0	30.2	66.0	82.6	42.9	51.5	8.34	6.98	15.19	18.92	9.78	11.84
Sioux Lookout Hydro Inc.	73.7	96.3	85.1	65.7	66.2	77.4	25.97	33.82	29.96	22.61	22.71	27.02
Atikokan Hydro Inc.	86.2	85.2	93.6	90.5	63.6	83.8	52.66	52.32	57.52	55.92	39.30	51.54
Fort Frances Power Corporation	62.9	98.6	67.5	86.3	128.0	88.7	16.81	26.13	17.95	23.09	34.18	23.63
Wellington North Power Inc.	147.2	160.4	133.4	133.8	146.7	144.3	38.68	41.87	34.57	33.95	36.20	37.05
Distributor Average						1,440.0						19.3

Vegetation Management O&M

Atikokan performs relatively well in its cost of vegetation management when compared to the distributor average and other VSU's. Atikokan's cost per customer is slightly less than the average distributor cost shown below. No need to make changes but continue to be cost effective and mindful of performance. Atikokan is pleased that it is performing well in this index given it has a dense population of trees and is seeing favorable results of its aggressive tree trimming in smaller line loses and educed outages due to trees.

Table 16: Vegetation Management O&M Indexes

Distributor	Table 3: Unit Cost Indexes by Distributor: Vegetation Management O&M											
	USoA [5135]											
	Cost ($1,000)						Unit Cost ($/Pole)					
	2018	2019	2020	2021	2022	Average	2018	2019	2020	2021	2022	Average
Chapleau Public Utilities Corporation	-	-	-	3.6	4.7	4.2	-	-	-	5.00	6.50	5.75
Hydro 2000 Inc.	6.9	5.0	3.3	5.3	7.0	5.5	18.88	13.59	9.08	13.32	17.63	14.50
Hearst Power Distribution Company Limited	2.6	14.1	13.0	7.2	8.7	9.1	1.66	9.12	8.42	4.65	5.56	5.88
Cooperative Hydro Embrun Inc.	17.1	9.6	6.2	7.2	7.0	9.4	39.65	22.17	17.90	20.78	20.14	24.13
Atikokan Hydro Inc.	41.6	53.5	34.1	41.8	41.7	42.6	31.34	40.30	25.72	31.43	31.35	32.03
Wellington North Power Inc.	77.6	50.9	67.0	68.2	66.4	66.0	41.11	26.91	35.26	35.60	34.50	34.67
Fort Frances Power Corporation	98.0	69.9	44.6	51.7	71.3	67.1	52.47	37.46	25.38	29.28	40.29	36.98
Sioux Lookout Hydro Inc.	84.3	88.0	66.7	66.8	53.3	71.8	30.92	32.17	24.29	24.26	19.31	26.19
Renfrew Hydro Inc.	69.8	105.4	64.7	68.3	91.3	79.9	39.22	59.16	36.28	38.18	50.91	44.75
Distributor Average						3,263.4						36.6

Lines O&M

For Lines O&M, Atikokan is an outlier and is underperforming in this index compared to the industry average and other VSU. Atikokan's average cost per customer is much greater than the average.

Table 17: Lines O&M Indexes

Distributor	Table 4: Unit Cost Indexes by Distributor: Lines O&M									
	USoA [5020:5030 + 5040:5050 + 5090:5095 + 5125:5130 + 5145:5155]									
	Cost ($1,000)					Unit Cost ($/Circuit km of Primary Line)				
	2019	**2020**	**2021**	**2022**	**Average**	**2019**	**2020**	**2021**	**2022**	**Average**
Cooperative Hydro Embrun Inc.	11.1	15.3	21.5	17.6	16.0	308.12	413.53	565.23	462.74	428.96
Hydro 2000 Inc.	16.5	14.4	19.5	18.5	16.8	787.86	687.59	926.55	879.84	800.67
Wellington North Power Inc.	44.1	57.6	71.1	88.7	57.6	512.87	661.77	799.39	985.07	658.01
Fort Frances Power Corporation	43.1	58.4	77.2	71.3	59.6	532.67	720.88	952.91	880.00	735.49
Renfrew Hydro Inc.	104.3	120.8	109.8	90.0	111.6	1,287.42	1,491.61	1,355.95	1,111.46	1,378.33
Chapleau Public Utilities Corporation	178.0	210.4	147.0	151.9	178.5	5,931.69	7,014.25	4,900.78	5,061.80	5,948.91
Hearst Power Distribution Company Limited	243.3	179.6	221.1	235.9	214.6	3,426.52	2,528.90	3,113.68	3,322.12	3,023.04
Atikokan Hydro Inc.	370.3	380.9	363.1	390.6	371.5	4,025.34	4,140.31	3,946.85	4,245.12	4,037.50
Sioux Lookout Hydro Inc.	468.9	501.3	497.1	513.7	489.1	768.71	821.87	814.94	839.38	801.84
Distributor Average					3,889.5					1,796.8

Stations O&M

For Stations O&M, Atikokan's average spend is less than the distributors and its unit cost per MVA is nearly on par to the industry distributor average. Based on this data, Atikokan does not need to make immediate changes but can continue to monitor the index.

Table 18: Stations O&M Indexes

Distributor	Table 5: Unit Cost Indexes by Distributor: Stations O&M											
	USoA [5016 + 5017 + 5114]											
	Cost ($1,000)						Unit Cost ($/MVA)					
	2018	2019	2020	2021	2022	Average	2018	2019	2020	2021	2022	Average
Fort Frances Power Corporation	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Hearst Power Distribution Company Limited	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Hydro 2000 Inc.	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Sioux Lookout Hydro Inc.	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Chapleau Public Utilities Corporation	2.3	2.5	1.4	2.4	6.7	3.1	372.97	392.68	226.07	376.58	1,075.13	488.7
Cooperative Hydro Embrun Inc.	6.8	3.6	24.8	7.0	11.6	10.8	297.69	157.96	1,062.89	302.15	498.54	463.8
Atikokan Hydro Inc.	23.1	12.9	13.6	27.4	15.1	18.4	1,440.88	804.61	852.23	1,710.40	1,372.26	1,236.1
Wellington North Power Inc.	23.2	42.4	44.3	49.4	54.9	42.8	859.70	1,569.77	1,639.76	1,829.83	2,033.12	1,586.4
Renfrew Hydro Inc.	64.6	52.0	38.9	53.8	67.8	55.4	2,582.55	2,078.92	1,556.38	2,150.34	2,712.29	2,216.1
Distributor Average						753.8						1,237.8

Poles, Towers O&M

Prior to the implementation of the APB, Atikokan did not report costs to the USoA 5120; therefore, this is why Atikokan has zero costs assigned for the historical years 2018 through 2020. It was during 2021, Atikokan started to utilize this USoA in adopting and following the OEB's Activity Based Benchmarking of programs. This could also explain why Atikokan's average cost per pole is less than the distributor average and most of the other VSU. Atikokan does not need to make immediate changes but can continue to monitor the index.

Table 19: Poles, Towers and Fixtures O&M

Distributor	Table 6: Unit Cost Indexes by Distributor: Poles, Towers and Fixtures O&M											
	USoA [5120]											
	Cost ($1,000)						Unit Cost ($/Pole)					
	2018	2019	2020	2021	2022	Average	2018	2019	2020	2021	2022	Average
Chapleau Public Utilities Corporation	0.3	-	-	1.8	2.8	1.1	0.42	-	-	2.54	3.89	1.48
Atikokan Hydro Inc.	-	-	-	2.6	5.4	2.6	-	-	-	1.98	4.06	1.98
Renfrew Hydro Inc.	3.6	3.7	2.8	2.9	1.5	3.3	2.05	2.08	1.55	1.62	0.85	1.86
Cooperative Hydro Embrun Inc.	5.7	3.9	5.3	6.5	7.2	5.6	13.14	9.06	15.42	18.81	20.79	14.27
Hydro 2000 Inc.	0.9	3.1	6.0	4.0	15.1	8.3	2.39	8.38	16.33	10.10	37.81	22.33
Wellington North Power Inc.	10.0	18.1	17.4	17.3	17.2	14.5	5.28	9.57	9.14	9.04	8.91	7.61
Fort Frances Power Corporation	27.5	17.9	11.8	12.2	5.9	20.5	14.74	9.59	6.72	6.92	3.34	11.10
Sioux Lookout Hydro Inc.	39.1	25.1	46.6	46.4	40.9	39.9	14.32	9.16	16.97	16.85	14.81	14.56
Hearst Power Distribution Company Limited	100.9	49.4	61.8	94.2	97.5	76.7	65.29	31.98	39.94	60.79	62.58	49.68
Synergy North Corporation	363.3	363.7	548.9	295.2	440.8	374.7	15.58	15.55	23.34	12.53	18.67	16.00
Distributor Average						549.2						10.75

Stations CAPEX

As displayed in the table, Atikokan has not had capital expenditures for stations; therefore, reporting no measure and for this reason, Atikokan cannot evaluate whether it is efficiency with its station capex costing compared to others.

Table 20: Dstations CAPEX Indexes

Distributor	Table 7: Unit Cost Indexes by Distributor: Stations CAPEX											
	USoA [1820] Capital Additions											
	Cost ($1,000)						Unit Cost ($/MVA)					
	2018	2019	2020	2021	2022	Average	2018	2019	2020	2021	2022	Average
Atikokan Hydro Inc.	-	-	-	-	-	-	-	-	-	-	-	-
Fort Frances Power Corporation	[redacted]											
Hearst Power Distribution Company Limited												
Hydro 2000 Inc.												
Sioux Lookout Hydro Inc.												
Wellington North Power Inc.	-	3.3	-	-	-	3.3	-	123	-	-	-	123.1
Cooperative Hydro Embrun Inc.	0.9	40.7	-	-	-	20.8	41	1,769	-	-	-	904.6
Chapleau Public Utilities Corporation	53.0	-	19.5	28.3	40.2	35.3	8,480	-	3,120	4,526	6,438	5,640.8
Renfrew Hydro Inc.	116.7	363.4	39.8	39.9	-	140.0	4,668	14,538	1,594	1,596	-	5,598.8
Distributor Average						1,865.2	-	-	-	-	-	3,912.9

Poles, Towers CAPEX

While when compared to other VSU, Atikokan has one of the highest costs per pole additions, Atikokan's average cost is less than the distributor average. Given the index, Atikokan does not need to directly address this program.

Table 21: Poles, Towers CAPEX Indexes

Distributor	Table 8: Unit Cost Indexes by Distributor: Poles, Towers and Fixtures CAPEX											
	USoA [1830] Capital Additions											
	Cost ($1,000)						Unit Cost ($/Pole Addition)					
	2018	**2019**	**2020**	**2021**	**2022**	**Average**	**2018**	**2019**	**2020**	**2021**	**2022**	**Average**
Cooperative Hydro Embrun Inc.	48.0	2.5	24.5	31.5	24.7	26	5,997	2,500	8,180	7,882	6,168	6,145
Hydro 2000 Inc.	29.1	41.2	24.0	26.0	83.8	41	5,827	5,891	5,992	6,491	6,445	6,129
Fort Frances Power Corporation	59.8	6.8	31.3	74.6	82.9	51	4,980	3,407	31,254	7,459	9,211	11,262
Chapleau Public Utilities Corporation	45.9	73.0	55.4	105.3	21.6	60	3,063	4,292	2,769	9,577	21,624	8,265
Hearst Power Distribution Company Limited	100.3	91.1	137.3	140.6	157.2	125	3,235	2,848	3,711	2,813	3,275	3,176
Sioux Lookout Hydro Inc.	163.7	145.3	133.2	115.6	177.2	147	7,794	5,382	5,122	3,854	5,537	5,538
Wellington North Power Inc.	134.4	171.6	178.0	157.5	174.4	163	2,636	2,959	2,870	3,089	4,055	3,122
Atikokan Hydro Inc.	383.8	89.2	76.1	192.6	141.8	177	9,138	5,246	3,805	3,379	3,375	4,988
Renfrew Hydro Inc.	221.6	231.3	289.0	407.3	388.8	308	5,539	8,898	11,114	10,720	10,509	9,356
Distributor Average						10,214.2	-	-	-	-	-	9,208.1

Line Transformers CAPEX

Review of the Line Transformer CAPEX index, Atikokan is under the distributor average and average is one of the least averages of the VSU. Atikokan does not it records transformers purchased for reserve to the USoA 1850 and does not record as CAPEX when placed into service. This could contribute to the lower average; whereas other utilities may be when put in service including the transformer cost and associated direct costs to place into service.

Table 22: Line Transformers CAPEX Indexes

Company_Name	Table 9: Unit Cost Indexes by Distributor: Line Transformers CAPEX											
	USoA [1850] Capital Additions											
	Cost ($1,000)						Unit Cost ($/Line Transformer Addition)					
	2018	2019	2020	2021	2022	Average	2018	2019	2020	2021	2022	Average
Chapleau Public Utilities Corporation	5.3	7.7	14.5	-	-	9.2	1,056	771	7,257	-	-	3,027.7
Hearst Power Distribution Company Limited	17.0	13.9	21.1	15.4	23.5	18.2	5,677	1,987	2,641	1,921	2,941	3,033.5
Atikokan Hydro Inc.	16.8	74.7	7.7	-	14.6	28.4	5,600	2,576	2,577	-	7,275	4,506.9
Renfrew Hydro Inc.	88.6	39.3	15.9	28.7	7.5	36.0	4,922	9,824	5,287	3,586	3,734	5,470.4
Fort Frances Power Corporation	61.8	37.0	31.3	3.4	121.6	51.0	-	6,174	15,658	428	30,408	13,166.8
Hydro 2000 Inc.	10.7	74.9	13.5	79.3	95.1	54.7	10,704	6,813	1,128	8,808	10,569	7,604.5
Sioux Lookout Hydro Inc.	49.9	60.5	121.2	54.5	49.2	67.1	7,135	4,658	6,379	3,630	8,201	6,000.4
Centre Wellington Hydro Ltd.	168.7	127.6	89.0	13.8	44.6	88.7	7,336	9,813	3,868	1,259	4,055	5,266.1
Cooperative Hydro Embrun Inc.	91.3	68.1	159.1	97.2	138.8	110.9	6,519	7,564	6,364	8,100	8,167	7,342.9
Wellington North Power Inc.	98.2	78.7	128.7	200.2	263.6	153.9	4,909	5,245	8,046	6,902	11,460	7,312.4
Distributor Average						4,128.0						10,450

Meters CAPEX

In review of Atikokan's Meter CAPEX, the utility performs on target, slightly under the industry average and within the range of the other small utilities. No immediate attention required; however, meter capex is driven from seal expires and failed meters and not a cost in Atikokan's control.

Table 23: Meters CAPEX Indexes

Distributor	Table 10: Unit Cost Indexes by Distributor: Meters CAPEX											
	USoA [1860] Capital Additions											
	Cost ($1,000)						Unit Cost ($/Customer)					
	2018	2019	2020	2021	2022	Average	2018	2019	2020	2021	2022	Average
Chapleau Public Utilities Corporation	10.9	-	3.1	4.3	1.4	4.9	9.00	0.00	2.56	3.47	1.11	4.03
Hydro 2000 Inc.	3.8	17.7	10.4	2.1	-	8.5	3.04	14.27	8.20	1.69	0.00	6.80
Cooperative Hydro Embrun Inc.	17.6	16.4	8.9	12.1	13.3	13.7	7.61	6.92	3.71	4.95	5.18	5.67
Hearst Power Distribution Company Limited	24.4	-	-	7.8	9.5	13.9	9.06	0.00	0.00	2.87	3.51	5.14
Sioux Lookout Hydro Inc.	11.5	35.9	9.4	7.5	9.9	14.8	4.05	12.59	3.31	2.57	3.40	5.18
Atikokan Hydro Inc.	21.1	15.1	29.8	0.5	-	16.6	12.87	9.28	18.33	0.29	0.00	10.19
Renfrew Hydro Inc.	51.4	17.7	66.1	29.8	26.2	38.2	11.91	4.08	15.21	6.82	5.98	8.80
Fort Frances Power Corporation	-	65.2	8.2	14.4	112.1	50.0	0.00	17.27	2.19	3.86	29.93	13.31
Wellington North Power Inc.	210.6	142.5	99.8	131.5	101.0	137.1	55.34	37.20	25.85	33.36	24.92	35.33
Distributor Average						2,729.3						11.85

Per filing requirements to the extent possible, Atikokan applied the costs included in this application to the PEG benchmarking forecast model to determine both the forecasted bridge and test year predicted costs. The table below shows both the historical 2023 results and the forecasted results.

Table 24: Cost Benchmarking

Cost Benchmarking Summary			
	2023 Actuals	**2024 Bridge**	**2025 Test**
Actual Total Cost	1,886,192	2,057,183	2,115,700
Predicted Total Cost	2,002,333	2,019,670	2,022,500
Difference	116,141	37,513	93,200
Percentage Difference (Cost Performance)	-5.98%	1.84%	4.50%
Three Year Average Performance	-2.9%	-2.1%	0.1%
Stretch Factor Cohort			
Annual Result	3	3	3
Three Year Average	3	3	3

The OEB's Distributor Yearbook data, in existence since 2005 has been a data set where details range from financial to operational information and customer service statistics amongst electricity distributors. This data is interesting and different from the APB PEG report data because it shows the factors and characteristics that may contribute to a utility's costs.

Reviewing the OEB 2022 Distributor Yearbook data Atikokan has sorted the utilities with less than 5,000 customers; those considered to be the very small utilities with similar like challenges with a smaller customer base compared to other utilities in the province. Atikokan has the third smallest customer count. Atikokan does however note that Chapleau entered a partnership with Hydro One during 2023 where Hydro One will own and operate the utility. As such the 2023 yearbook data may show different results.

Table 25: Atikokan 2022 Yearbook Data and VSU Comparators (sorted by customers)

LDC	TOTAL CUSTOMERS	TOTAL SERVICE AREA (sq km)	Total km of Line	OM & A per customer ($)	# of Customers per square km of Service Area	# of Customers per km of Line
Chapleau Public Utilities Corporation	1,224.00	14.00	54.00	862.00	87.43	22.67
Hydro 2000 Inc.	1,268.00	9.00	21.00	664.00	140.89	60.38
Atikokan Hydro Inc.	1,619.00	380.00	92.00	1,098.00	4.26	17.60
Cooperative Hydro Embrun Inc.	2,575.00	5.00	38.00	482.00	515.00	67.76
Hearst Power Distribution Company Limited	2,720.00	93.00	97.00	599.00	29.25	28.04
Sioux Lookout Hydro Inc.	2,915.00	539.00	714.00	836.00	5.41	4.08
Fort Frances Power Corporation	3,744.00	32.00	81.00	737.00	117.00	81.00
Wellington North Power Inc.	4,053.00	14.00	221.00	863.00	289.50	18.34
Renfrew Hydro Inc.	4,384.00	13.00	81.00	640.00	337.23	54.12

The yearbook results shows that Atikokan has the highest OM&A per customer. The other two utilities (Chapleau and Hydro 2000) that have less cost per customer do have less customers, but they also have less total service area and KM of line to maintain.

Table 26: Atikokan 2022 Yearbook Data and VSU Comparators (sorted by OM&A)

LDC	TOTAL CUSTOMERS	TOTAL SERVICE AREA (sq km)	Total km of Line	OM & A per customer ($)	# of Customers per square km of Service Area	# of Customers per km of Line
Cooperative Hydro Embrun Inc.	2,575.00	5.00	38.00	482.00	515.00	67.76
Hearst Power Distribution Company Limited	2,720.00	93.00	97.00	599.00	29.25	28.04
Renfrew Hydro Inc.	4,384.00	13.00	81.00	640.00	337.23	54.12
Hydro 2000 Inc.	1,268.00	9.00	21.00	664.00	140.89	60.38
Fort Frances Power Corporation	3,744.00	32.00	81.00	737.00	117.00	81.00
Sioux Lookout Hydro Inc.	2,915.00	539.00	714.00	836.00	5.41	4.08
Chapleau Public Utilities Corporation	1,224.00	14.00	54.00	862.00	87.43	22.67
Wellington North Power Inc.	4,053.00	14.00	221.00	863.00	289.50	18.34
Atikokan Hydro Inc.	1,619.00	380.00	92.00	1,098.00	4.26	17.60

It is difficult to wholly compare each utility to one another given the service area distribution characteristic differences. Atikokan strives to control its costs and limit the OM&A per customer but finds it difficult given most of its costs are fixed in nature and the large service area it most maintains with very few customers per km or service area and line. Therefore, the utility finds most of its costs out of its control. The industry is heavily regulated and the nature of most of Atikokan's expenses are to keep up with those regulations while providing its customers with safe and reliable supply of electricity. Atikokan does however have redundancies in place for reliability and that does come at a cost but believes this is of value to its customers.

2.1.7 Facilitating Innovation

The Ontario Energy Board Act has changed to facilitate innovation in the electricity sector. Innovation can relate to the use of new technology, or new ways in which to use existing technologies. It could also include innovative business practise, including relationships with others to enhance services to customers and share costs.

Innovation is challenging given Atikokan's limited resources. However, memberships and advocacy's Atikokan has with the Electricity Distributors Association and Utilities Standards Forum help Atikokan have the tools and insight to the changing industry and how to meet regulatory policy demands and or innovative opportunities in the industry. Atikokan's shared services agreement with Synergy North is instrumental in Atikokan's continued success in sharing costs and enhancing services available to its customers.

Locally, the Town of Atikokan has an Electric Vehicle Charging Station. In support of Electric Vehicles and the industries change to further electrification, Atikokan Hydro has partnered with the owner of the charging station and will reset the breaker to the charging station when it is reported offline.

2.1.8 Financial Information

Atikokan Hydro's last two years of Financial Statements included in Appendix A.

The following are not applicable:

- Annual report and management discussion and analysis
- Rating agency report
- No Prospectuses
- No Change in tax status
- No departures from accounting order
- No departures from USoA
- No non-distribution businesses as generation.

2.1.9 Distributor Consolidation

Atikokan has not amalgamated or consolidated with another distributor. Atikokan Hydro does however collaborate with other utilities specifically the northwest group (Synergy North, Fort Frances Power Corp and Sioux Lookout Hydro) to help reduce its costs and increase its effectiveness and meet regulatory mandates with shared services.

In its 2021 mandate letter to the OEB, the Minister of Energy directed the OEB to require from LDC's with fewer than 30k customers to file information within their CoS in regard to collaboration and consolidation opportunities. Page 4 of the letter states the following:

"The OEB should continue to ensure that the structure and operations of the distribution sector constantly evolve towards optimal efficiency. To that end, the OEB should explore opportunities to enable proactive investment in energy infrastructure, such as protection and refurbishment, where utilities can prove there are long-term economic and reliability benefits to ratepayers. In previous years, these efficiencies have been found both through utility mergers/acquisitions and with the formation of innovative partnerships between utilities. Considering this, I also ask that the OEB require LDCs with fewer than 30,000 customers to file information within their cost-of-service

applications on the extent to which they have investigated potential opportunities from consolidation or collaboration/partnerships with other distributors."

With the synergies of the Northwest Group and a request for proposal lead by Synergy North on behalf of the group, Atikokan Hydro was able to meet the mandated Green Button Initiative; these implementation costs were shared among the group. The Northwest Groups collaborative efforts data back to the implementation of smart meters. Atikokan Hydro has a shared service agreement with Synergy North as its metering service provider who also provides backend billing support and other ad hoc services and joint plans as necessary. In the past Atikokan has collaborated with the northwest group for CDM initiatives. There may be opportunities to collaborate again for CDM initiatives in the future.

Atikokan also utilizes distributor collaboration through leadership of industry groups like the Electricity Distributor's Association, Utilities Standards Forum and other informal communications to help with the sharing of ideas, information and best practices within the industry.

Atikokan will continue to network with our shareholder, stakeholders and other utilities to share best practices and gain operational efficiencies through collaboration where achievable.

2.1.10 Impacts of COVID-19 Pandemic

Atikokan Hydro is not seeking recovery of any costs or lost revenue from COVID-19 pandemic. The cost of loss revenues due to demand reductions were not material nor for an extended period to warrant recovery.

Since COVID-19 Atikokan has however seen supply chain challenges that were not prevalent pre COVID-19. The industry is challenged with significant cost increases and extended lead times to receive material causing delays and disruptions to plans. Atikokan finds it must plan further out and hold inventory and material levels that it historically has not had to in the past.

Appendix A: Audited Financial Statements

The most current audited financial statements are included covering the most recent two historical years; 2023 and 2022.

Atikokan Hydro Inc.
Financial Statements
For the year ended December 31, 2023

Contents

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Independent Auditor's Report

To the Shareholder of Atikokan Hydro Inc.

Opinion

We have audited the financial statements of Atikokan Hydro Inc. (the "Entity"), which comprise the Statement of Financial Position as at December 31, 2023, and the Statement of Comprehensive Income, the Statement of Changes in Equity and the Statement of Cash Flows for the year then ended, and Notes to Financial Statements, including material accounting policy information.

In our opinion, the accompanying financial statements present fairly, in all material respects, the financial position of the Entity as at December 31, 2023, and its financial performance and its cash flows for the year then ended in accordance with International Financial Reporting Standards.

Basis for Opinion

We conducted our audit in accordance with Canadian generally accepted auditing standards. Our responsibilities under those standards are further described in the *Auditor's Responsibilities for the Audit of the Financial Statements* section of our report. We are independent of the Entity in accordance with the ethical requirements that are relevant to our audit of the financial statements in Canada, and we have fulfilled our other ethical responsibilities in accordance with these requirements. We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

Responsibilities of Management and Those Charged with Governance for the Financial Statements

Management is responsible for the preparation and fair presentation of these financial statements in accordance with International Financial Reporting Standards, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the financial statements, management is responsible for assessing the Entity's ability to continue as a going concern, disclosing, as applicable, matters related to going concern and using the going concern basis of accounting unless management either intends to liquidate the Entity or to cease operations, or has no realistic alternative but to do so.

Those charged with governance are responsible for overseeing the Entity's financial reporting process.

Auditor's Responsibilities for the Audit of the Financial Statements

Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditor's report that includes our opinion. Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with Canadian generally accepted auditing standards will always detect a material misstatement when it exists. Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of these financial statements.

As part of an audit in accordance with Canadian generally accepted auditing standards, we exercise professional judgment and maintain professional skepticism throughout the audit. We also:

- Identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations or the override of internal control.

- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Entity's internal control.

- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.

- Conclude on the appropriateness of management's use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Entity's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditor's report to the related disclosures in the financial statements or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditor's report. However, future events or conditions may cause the Entity to cease to continue as a going concern.

- Evaluate the overall presentation, structure and content of the financial statements, including the disclosures, and whether the financial statements represent the underlying transactions and events in a manner that achieves fair presentation.

We communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.

BDO Canada LLP

Chartered Professional Accountants, Licensed Public Accountants

Fort Frances, Ontario
April 19, 2024

Atikokan Hydro Inc.
Statement of Financial Position

December 31	2023	2022
Assets		
Current assets		
Cash and cash equivalents	$ 889,935	$ 536,570
Accounts receivable (Note 6)	303,034	299,264
Unbilled revenue (Note 6)	373,208	404,966
Inventory (Note 15)	217,965	200,945
Prepaids	181,296	47,294
Payments in lieu of Corporate taxes receivable (Note 8)	83,317	17,399
Total current assets	2,048,755	1,506,438
Property, plant and equipment (Note 4)	3,400,601	3,424,076
Deferred income taxes (Note 8)	27,493	75,808
Total non-current assets	3,428,094	3,499,884
Regulatory deferral account debits and related deferred tax (Note 3)	60,387	73,389
	$ 5,537,236	$ 5,079,711
Liabilities and Shareholder's Equity		
Current liabilities		
Accounts payable and accrued liabilities (Note 9)	$ 810,350	$ 553,486
Customer deposits (Note 7)	17,880	19,100
Current portion of long-term debt (Note 10)	56,486	62,736
Total current liabilities	884,716	635,322
Customer deposits (Note 7)	160,919	171,902
Long-term debt (Note 10)	22,758	79,244
Contributions in aid of construction (Note 5)	307,686	305,981
Total liabilities	1,376,079	1,192,449
Shareholder's equity		
Share capital (Note 11)	2,539,963	2,539,963
Retained earnings	1,419,309	1,126,644
	3,959,272	3,666,607
Regulatory deferral account credits and related deferred tax (Note 3)	201,885	220,655
	$ 5,537,236	$ 5,079,711

On behalf of the Board:

Dennis Brown ______ Director

Rob Ferg ______ Director

The accompanying notes are an integral part of these financial statements.

Atikokan Hydro Inc.
Statement of Comprehensive Income

For the year ended December 31	2023	2022
Revenue (Note 5)		
Electricity sales and distribution	$ 4,874,544	$ 4,960,897
Other	129,356	106,333
	5,003,900	5,067,230
Expenses (Note 16)		
Administration	500,261	485,017
Depreciation	211,135	207,512
Billing and collecting	190,469	180,502
Distribution expense operation	402,349	431,501
Distribution expense maintenance	155,191	128,373
Energy cost	3,291,014	3,517,184
Demand management program expense	-	200
	4,750,419	4,950,289
Income from operating activities	253,481	116,941
Finance income (Note 17)	59,825	23,919
Finance cost (Note 17)	(30,091)	(14,655)
Loss on disposal of property, plant and equipment	(4,016)	(7,436)
Income before payment in lieu of Corporate taxes	279,199	118,769
Provision for recovery (payment) in lieu of Corporate taxes Current (Note 8)	21,474	(19,945)
Income for the year before net movements in regulatory deferral account balances	300,673	98,824
Net movement in regulatory deferral account balances related to profit or loss and the related deferred tax movement	(8,008)	37,473
Total comprehensive income	$ 292,665	$ 136,297

The accompanying notes are an integral part of these financial statements.

Atikokan Hydro Inc.
Statement of Changes in Equity

	Share Capital	Retained Earnings	Total
Balance at January 1, 2022	$ 2,539,963	$ 990,347	$ 3,530,310
Net income after net movements in regulatory balances	-	136,297	136,297
December 31, 2022	2,539,963	1,126,644	3,666,607
Net income after net movements in regulatory balances	-	292,665	292,665
December 31, 2023	**$ 2,539,963**	**$ 1,419,309**	**$ 3,959,272**

The accompanying notes are an integral part of these financial statements.

Atikokan Hydro Inc.
Statement of Cash Flows

For the year ended December 31	2023	2022
Cash provided by (used in)		
Operating activities		
Net income after net movements in regulatory balances	$ 292,665	$ 136,297
Adjustments to reconcile income to net cash used in operating activities		
Depreciation of property, plant and equipment	211,135	207,512
Loss on disposal of property, plant and equipment	4,016	7,436
Amortization of contributions in aid of construction	(16,282)	(7,288)
Deferred taxes	48,315	25,209
	539,849	369,166
Changes in non-cash working capital balances		
Accounts receivable	(3,770)	136,642
Unbilled revenue	31,758	(894)
Inventory	(17,020)	(43,018)
Prepaids	(134,001)	(15,108)
Accounts payable	256,864	(178,211)
Payment in lieu of Corporate taxes receivable	(65,918)	(12,782)
	607,762	255,795
Investing activities		
Additions to property, plant and equipment	(191,678)	(200,299)
Changes in regulatory deferral account balances	(5,768)	33,885
	(197,446)	(166,414)
Financing activities		
Repayment of long-term debt	(62,736)	(123,486)
Increase in customer deposits held	(12,202)	29,845
Contributions received in aid of construction	17,987	91,282
	(56,951)	(2,359)
Increase in cash during the year	353,365	87,022
Cash and cash equivalents, beginning of year	536,570	449,548
Cash and cash equivalents, end of year	$ 889,935	$ 536,570
Supplementary cash flow information		
Total interest paid	$ 30,091	$ 14,655

The accompanying notes are an integral part of these financial statements.

1. Corporate Information

Atikokan Hydro Inc.'s (the "Corporation") main business activity is the distribution of electricity under a license issued by the Ontario Energy Board ("OEB"). The Corporation owns and operates an electricity distribution system, which delivers electricity to approximately 1,600 customers located in Atikokan, Ontario.

The Province, through its regulator, the OEB, exercises statutory authority through setting or approving all rates charged by the Corporation and establishing standards of service for the Corporation's customers. Rates are set by the OEB on an annual basis for May 1 to April 30.

Operating in a regulated environment exposes the Corporation to regulatory and recovery risk.

Regulatory risk is the risk that the Province and its regulator, the OEB, could establish a regulatory regime that imposes conditions that restrict the electricity distribution business from achieving an acceptable rate of return that permits financial sustainability of its operations including the recovery of expenses incurred for the benefit of other market participants in the electricity industry such as transition costs and other regulatory assets. All requests for changes in electricity distribution charges require the approval of the OEB.

Regulatory developments in Ontario's electricity industry, including current and possible future consultations between the OEB and interested stakeholders, may affect distribution rates and other permitted recoveries in the future. Atikokan Hydro Inc. is subject to a cost of service regulatory mechanism under which the OEB establishes the revenues required (i) to recover the forecast operating costs, including depreciation and amortization and income taxes, of providing the regulated service, and (ii) to provide a fair and reasonable return on utility investment, or rate base. As actual operating conditions may vary from forecast, actual returns achieved can differ from approved returns.

The address of the Corporate office and principal place of business is 117 Gorrie Street, P.O. Box 1480, Atikokan, Ontario, Canada.

The sole shareholder of the Corporation is the Corporation of the Town of Atikokan.

2. Basis of Preparation

a) Statement of Compliance

The financial statements of Atikokan Hydro Inc. have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB").

The financial statements were authorized for issue by the Board of Directors on April 19, 2024.

2. **Basis of Preparation** (continued)

b) Basis of Measurement

The financial statements have been prepared on a historical cost basis. The financial statements are presented in Canadian dollars (CDN$), which is also the Corporation's functional currency, and all values are rounded to the nearest dollar, unless otherwise indicated.

c) Judgment and Estimates

The preparation of financial statements in compliance with IFRS requires management to make certain critical accounting estimates. It also requires management to exercise judgment in applying the Corporation's accounting policies. The areas involving critical judgments and estimates in applying accounting policies that have the most significant risk of causing material adjustment to the carrying amounts of assets and liabilities recognized in the financial statements within the next financial year are:

- The determination of impairment of accounts receivables and unbilled service revenues; and the incorporation of forward-looking information into the measurement of the expected credit loss ("ECL") (Note 6);
- The determination of useful lives of property, plant and equipment (Note 4);
- The recognition and measurement of regulatory deferral account balances (Note 3); and
- The determination for the provision for Payment in Lieu of Taxes since there are many transactions and calculations for which the ultimate tax determination is uncertain (Note 8).

In addition, in preparing the financial statements, the notes to the financial statements were ordered such that the most relevant information was presented earlier in the notes and the disclosures that management deemed to be immaterial were excluded from the notes to the financial statements. The determination of the relevance and materiality of disclosures involved significant judgment.

3. Regulatory Deferral Account Balances

The Corporation applies IFRS 14, Regulatory Deferral Accounts, to reflect the impact of regulation on its operations. In accordance with IFRS 14, the Corporation continues to apply the accounting policies it applied in accordance with the pre-changeover Canadian GAAP for the recognition, measurement and impairment of assets and liabilities arising from rate regulation. These are referred to as regulatory deferral account balances. Regulatory deferral account balances are recognized and measured initially and subsequently at cost. They are assessed for impairment on the same basis as other non-financial assets.

Regulatory deferral account credit balances are associated with the collection of certain revenues earned in the current period or in prior period(s), that are expected to be returned to consumers in future periods through the rate-setting process.

Regulatory deferral account debit balances represent future revenues associated with certain costs incurred in the current period or in prior period(s), that are expected to be recovered from consumers in future periods through the rate-setting process. Management continually assesses the likelihood of recovery of regulatory assets. If recovery through future rates is no longer considered probable, the amounts would be charged to the results of operations in the period that the assessment is made.

All amounts deferred as regulatory deferral account debit balances are subject to approval by the OEB. As such, amounts subject to deferral could be altered by the regulators. Remaining recovery periods are those expected and the actual recovery or settlement periods could differ based on the OEB approval. Due to previous, existing or expected future regulatory articles or decisions, the Corporation has the following amounts expected to be recovered by customers (returned to customers) in future periods and as such regulatory deferral account balances are comprised of the following.

3. Regulatory Deferral Account Balances (continued)

	January 1, 2022	Balances arising in the period	Recovery/ reversal	Other movements	December 31, 2022	Balances arising in the period	Recovery/ reversal	Other movements	December 31, 2023
Regulatory Deferral Account Debit									
Settlement variances	$ 72,957	$ 40,406	$ (39,974)	$ -	$ 73,389	$ (1,966)	$ (11,036)	$ -	$ 60,387
Regulatory Deferral Account Credit									
Deferred tax	101,017	(25,209)	-	-	75,808	(48,315)	-	-	27,493
PILs and tax variances	(14,933)	3,597	-	31,814	20,478	1,280	-	-	21,758
Other deferral accounts	100,254	24,115	-	-	124,369	28,265	-	-	152,634
	186,338	2,503	-	31,814	220,655	(18,770)	-	-	201,885
Net Regulatory (Liabilities)/ Assets	$ (113,381)	$ 37,903	$ (39,974)	$ (31,814)	$ (147,266)	$ 16,804	$ (11,036)	$ -	$ (141,498)

The "balances arising in the period" column consists of new additions to regulatory balances (for both debits and credits). The "recovery/reversal" column consists of amounts collected through rate riders or transactions reversing an existing regulatory balance. The "other movements" column consists of impairment and reclassification between the regulatory debit and credit balances. For the year ended December 31, 2023, there was no impairment recorded. For the year ended December 31, 2022, impairment of the PILs and tax variances was recorded in the amount of $31,814 due to the assessment that the tax variance for the change in the corporate tax rate is considered doubtful to be recovered.

3. Regulatory Deferral Account Balances (continued)

(i) *Settlement Variances*

This account is comprised of the variances between amounts charged by the Corporation to customers, based on regulated rates, and the corresponding cost of non-competitive electricity service incurred by the Corporation after May 1, 2002. The settlement variances relate primarily to service charges, non-competitive electricity charges, imported power charges and the global adjustment.

(ii) *Other Deferral Accounts*

Other deferral accounts includes smart meter deferral accounts and pole attachment revenue variances.

During 2018, the OEB directed that the account previously used to track stranded meters, now fully recovered, be used to track variances resulting from a change in the Smart Metering Entity Charge collected from customers on behalf of the Independent Electricity System Operator. Amounts overpaid by customers as a result of the change will be approved for repayment in the Corporation's next cost-based rate application to the OEB.

Pole attachment revenue variances consists of additional amounts collected from carriers for wireline pole attachment charges due to an increase in the OEB's legislated rate, which will be paid to customers when the revenue is included in the Corporation's next cost-based rate application to the OEB.

(iii) *Deferred Tax*

The recovery from, or refund to, customers of future income taxes through future rates is recognized as a regulatory deferral account balance. The Corporation has recognized a deferred tax asset of $27,493 (2022 - $75,808) and a corresponding regulatory deferral account credit balance of $27,493 (2022 - $75,808).

3. Regulatory Deferral Account Balances (continued)

(iv) *PILs and Tax Variances*

PILs and tax variances includes CCA and tax rate variances.

The CCA change regulatory balance arose from the revenue requirement impact of accelerated capital cost allowance deductions under the Accelerated Investment Incentive tax measure which received Royal Assent on June 21, 2019, and the immediate expensing rules which received Royal Assent on June 23, 2022. The tax rate variance consists of the impact of a tax rate change due to the Corporation's ineligibility for the small business deduction starting in 2019.

These amounts will be brought forward for disposition in the Corporation's next cost-based rate application to the OEB, with the OEB to determine the method of disposition at the time of the application. During 2022, it was determined that the OEB is unlikely to allow the future disposition of the tax rate variance, and as a result the amount is considered impaired and an allowance has been recorded.

4. Property, Plant and Equipment

Property, plant and equipment (PP&E) are recognized at cost including eligible borrowing costs. There were no borrowing costs capitalized during the years ended December 31, 2023, or December 31, 2022.

Major spares such as spare transformers and other items kept as standby/back up equipment are accounted for as PP&E since they support the Corporation's distribution system reliability.

Depreciation of PP&E is recorded in the statement of comprehensive income on a straight-line basis over the estimated useful life of the related asset. The estimated useful lives, residual values and depreciation methods are reviewed at the end of each annual reporting period, with the effect of any changes in estimate being accounted for on a prospective basis. The estimated useful lives are as follows:

Buildings	40 years
Distribution equipment	45 to 60 years
Other equipment	10 years
Computer equipment and software	5 years
Automotive equipment	various straight line basis
Land is not depreciated.	

December 31, 2023

4. Property, Plant and Equipment (continued)

							2023
	Land	Buildings	Distribution Equipment	Automotive Equipment	Computer Equipment and Software	Other Equipment	Total
Cost, beginning of year	$ 15,588	$ 703,344	$ 5,805,623	$ 943,196	$ 89,614	$ 229,257	$ 7,786,622
Additions	-	-	189,881	-	-	1,797	191,678
Disposals	-	-	(22,409)	-	-	-	(22,409)
Cost, end of year	15,588	703,344	5,973,095	943,196	89,614	231,054	7,955,891
Accumulated amortization, beginning of year	-	447,391	3,063,446	589,041	77,179	185,489	4,362,546
Depreciation	-	11,930	126,427	57,764	7,513	7,501	211,135
Disposals	-	-	(18,391)	-	-	-	(18,391)
Accumulated amortization, end of year	-	459,321	3,171,482	646,805	84,692	192,990	4,555,290
Net carrying amount, end of year	$ 15,588	$ 244,023	$ 2,801,613	$ 296,391	$ 4,922	$ 38,064	$ 3,400,601

December 31, 2023

4. Property, Plant and Equipment (continued)

								2022
	Land	Buildings	Distribution Equipment	Automotive Equipment	Computer Equipment and Software	Other Equipment	Construction in progress	Total
Cost, beginning of year	$ 15,588	$ 683,677	$ 5,685,715	$ 930,057	$ 83,114	$ 211,695	$ 26,904	$ 7,636,750
Additions	-	33,697	129,401	13,139	6,500	17,562	-	200,299
Transfers into service	-	-	26,904	-	-	-	(26,904)	-
Disposals	-	(14,030)	(36,397)	-	-	-	-	(50,427)
Cost, end of year	15,588	703,344	5,805,623	943,196	89,614	229,257	-	7,786,622
Accumulated amortization, beginning of year	-	450,165	2,966,362	531,934	71,091	178,473	-	4,198,025
Depreciation	-	11,256	126,045	57,107	6,088	7,016	-	207,512
Disposals	-	(14,030)	(28,961)	-	-	-	-	(42,991)
Accumulated amortization, end of year	-	447,391	3,063,446	589,041	77,179	185,489	-	4,362,546
Net carrying amount, end of year	$ 15,588	$ 255,953	$ 2,742,177	$ 354,155	$ 12,435	$ 43,768	$ -	$ 3,424,076

5. Revenue Recognition

	2023	2022
Electricity sales and distribution		
Revenue from contracts with customers		
Electricity sales (a)	$ 3,299,021	$ 3,479,712
Distribution revenue (a)	1,559,241	1,473,897
Revenue from other sources		
Capital contributions (b)	16,282	7,288
	$ 4,874,544	$ 4,960,897
Other		
Revenue from contracts with customers		
Ancillary services revenue (c)	$ 80,350	$ 57,745
Pole rentals (c)	32,609	32,609
Other regulatory service and collection charges (c)	9,559	7,535
Miscellaneous (c)	6,838	8,244
Revenue from other sources		
Demand management program revenue (d)	-	200
	$ 129,356	$ 106,333
Total revenue		
Revenue from contracts with customers	$ 4,987,618	$ 5,059,742
Revenue from other sources	16,282	7,488
	$ 5,003,900	$ 5,067,230

a) Electricity sales and distribution revenue

As a licensed distributor, the Corporation is responsible for billing customers for electricity generated by third parties and the related costs of providing electricity service, such as transmission services and other services provided by third parties. The Corporation is required, pursuant to regulation, to remit such amounts to these third parties, irrespective of whether the Corporation ultimately collects these amounts from customers. The Corporation has determined that they are acting as a principal for the electricity distribution and, therefore, have presented the electricity revenues on a gross basis.

Revenues from the sale and distribution of electricity is recognized over time on an accrual basis upon delivery of the electricity, including unbilled revenues accrued in respect of electricity delivered but not yet billed. Sale and distribution of electricity revenue is comprised of customer billings for distribution service charges. Customer billings for distribution service charges are recorded based on meter readings, and are generally due within 30 days of the billing date.

5. **Revenue Recognition** (continued)

b) Capital contributions

Certain assets may be acquired or constructed with financial assistance in the form of contributions from customers when the estimated revenue is less than the cost of providing service or where special equipment is needed to supply the customers' specific requirements. Since the contributions will provide customers with ongoing access to the supply of electricity, these contributions are classified as contributions in aid of construction and are amortized as revenue on a straight-line basis over the useful life of the constructed or contributed asset.

When an asset is received as a capital contribution, the asset is initially recognized at its fair value, with the corresponding amount recognized as contributions in aid of construction.

The continuity of deferred contributions in aid of construction is as follows:

	2023	2022
Contributions in aid of construction, beginning of year	$ 305,981	$ 221,987
Contributions in aid of construction received	17,987	91,282
Contribution in aid of construction recognized as distribution revenue	(16,282)	(7,288)
Contributions in aid of construction, end of year	$ 307,686	$ 305,981

All contributions in aid of construction are cash contributions. There have not been any contributions of property, plant and equipment.

c) Other revenues

Other revenues, which include revenues from pole rentals, collection charges and other ancillary services and miscellaneous revenues are recognized at the time the services are provided. Where the Corporation has an ongoing obligation to provide services, revenues are recognized as the service is performed and amounts billed in advance are recognized as deferred revenue.

d) Demand management program revenue

Demand management program revenue, received for the purposes of administering electrical consumption conservation and demand management programs for the benefit of customers, is recognized in accordance with IAS 20 *Accounting for Government Grants and Disclosure of Government Assistance* when there is reasonable assurance that the funding will be received and that the Corporation will comply with the conditions attached to the funding. Funding received that is not spent on eligible programs must be repaid and is recorded as a liability.

6. Accounts Receivable and Unbilled Revenue

Accounts Receivable

	2023	2022
Due from related parties	$ 3,410	$ 9,085
Due from other customers	305,555	296,103
Loss allowance	(5,931)	(5,924)
	$ 303,034	$ 299,264

Unbilled Revenue

Unbilled revenue reflects the electricity delivered but not yet billed to customers. Customer billings generally occur within 30 days of delivery. The change in unbilled revenue is set out in the following table:

	2023	2022
Due from other customers	$ 373,277	$ 405,042
Loss allowance	(69)	(76)
	$ 373,208	$ 404,966

a) Recognition and initial measurement

The Corporation initially recognizes accounts receivable on the date on which they are originated and unbilled revenue on the date on which the Corporation delivers the electricity but has not yet billed the customer. Accounts receivable and unbilled revenue are initially measured at fair value.

b) Classification and subsequent measurement

Accounts receivable and unbilled revenue are classified and subsequently measured at amortized cost, using the effective interest rate method, because they meet the solely payments of principal and interest criterion and are held within a business model whose objective is to hold financial assets in order to collect contractual cash flows. The carrying amount is reduced through the use of a loss allowance and the amount of the related loss allowance is recognized in profit or loss. Subsequent recoveries of receivables and unbilled service revenue previously provisioned are credited to profit or loss.

c) Fair value measurement

Due to their short-term nature, the carrying amounts of accounts receivable and unbilled revenue approximates their fair value.

6. **Accounts Receivable and Unbilled Revenue** (continued)

d) Credit risk

Credit risk associated with accounts receivable and unbilled revenue is managed through collection of security deposits from customers in accordance with directions provided by the OEB. Where the security posted is in the form of cash or cash equivalents, these amounts are recorded in the accounts as deposits, which are reported separately from the Corporation's own cash and cash equivalents. Deposits to be refunded to customers within the next fiscal year are classified as a current liability (Note 7). Interest rates paid on customer deposits are based on the Bank of Canada's prime business rate less 2%.

The Corporation's credit risk associated with accounts receivable and unbilled revenue is primarily related to payments from distribution customers. The Corporation has approximately 1,600 customers, the majority of which are residential. The Corporation considers an account receivable to be in default when the customer is unlikely to pay its credit obligations in full, without recourse by the Corporation, such as realizing security (if any is held). Accounts are past-due (in default) when the customers have failed to make the contractually requirements payments when due, which is generally within 30 days of the billing date.

The Corporation considers accounts receivable and unbilled revenues to be credit-impaired when the customer has amounts more than 90 days past the billing date.

The following table provides information about the exposure to credit risk and ECLs for accounts receivable and unbilled revenue by level of delinquency.

6. Accounts Receivable and Unbilled Revenue (continued)

At December 31, 2023	Gross	Loss Allowance	Net
Less than 30 days past billing date and unbilled amounts	$ 647,221	$ 120	$ 647,101
30-60 days past billing date	16,092	180	15,912
61-90 days past billing date	5,745	600	5,145
More than 90 days past billing date	13,184	5,100	8,084
	$ 682,242	$ 6,000	$ 676,242

At December 31, 2022			
Less than 30 days past billing date and unbilled amounts	$ 639,424	$ 120	$ 639,304
30-60 days past billing date	30,873	180	30,693
61-90 days past billing date	6,100	600	5,500
More than 90 days past billing date	33,834	5,100	28,734
	$ 710,231	$ 6,000	$ 704,231

The Corporation measures the loss allowance at an amount equal to the lifetime ECL for accounts receivables and unbilled revenue. The lifetime ECL is estimated based on the expected losses over the expected life of the accounts receivable and unbilled revenue arising from default events occurring in the lifetime of the instrument.

The Corporation uses a provision matrix to measure the lifetime ECL of accounts receivable and unbilled revenue from individual customers which accounts for exposures in different customer classes. Expected credit loss is measured on the basis of a loss rate approach. The Corporation develops loss rates based on historical default and loss experiences for its customers, adjusted for current economic conditions and forecasts of future economic conditions including local unemployment rates, local economic outlook, credit environment and other relevant economic variables impacting subsets of the Corporation's customers.

6. **Accounts Receivable and Unbilled Revenue** (continued)

The same factors are considered when determining whether to write off accounts receivable and unbilled revenue amounts. This generally occurs when there is no realistic prospect of recovery. However, accounts written off could still be subject to enforcement activities. No accounts are written off directly to the provision for credit losses.

The following tables present a summary of the activity related to the Corporation's accounts receivable and unbilled revenue loss allowances.

	2023	2022
Accounts Receivable		
Balance, January 1	$ 5,924	$ 5,940
Additions (provision for credit loss)	315	3,044
Accounts written off, net of recoveries	(308)	(3,060)
Balance, December 31	$ 5,931	$ 5,924
Unbilled Revenue		
Balance, January 1	$ 76	$ 60
Additions (provision for credit loss)	(7)	16
Balance, December 31	$ 69	$ 76

There were no written off amounts charged to customer accounts receivable loss allowance or unbilled revenue loss allowance that were still subject to enforcement activity as at December 31, 2023, or December 31, 2022.

7. Customer Deposits

Customer deposits represents cash deposits from electricity distribution customers and retailers, as well as construction deposits.

Deposits from electricity distribution customers are refundable to customers demonstrating an acceptable level of credit risk as determined by the Corporation in accordance with policies set out by the OEB or upon termination of their electricity distribution service.

	2023	2022
Long-term portion of deposits	$ 160,919	$ 171,902
Current portion of deposits	17,880	19,100
	$ 178,799	$ 191,002

a) Recognition and initial measurement

The Corporation initially recognizes customer deposits on the date on which the Corporation receives the deposit. Customer deposits are initially measured at fair value.

b) Classification and subsequent measurement

Customer deposits are classified and subsequently measured at amortized cost, using the effective interest rate method.

c) Fair value measurement

The fair value of customer deposits approximates their carrying amounts taking into account interest accrued on the outstanding balance.

8. Payments in Lieu of Taxes Payable

The Corporation is a Municipal Electricity Utility ("MEU") for purposes of the payments in lieu of taxes ("PILs") regime contained in the Electricity Act, 1998. As a MEU, the Corporation is exempt from tax under the Income Tax Act (Canada) and the Corporations Tax Act (Ontario).

Under the Electricity Act, 1998, the Corporation is required to make, for each taxation year, PILs to Ontario Electricity Financial Corporation ("OEFC"). These payments are calculated in accordance with the rules for computing taxable income and taxable capital and other relevant amounts contained in the Income Tax Act (Canada) and the Corporations Tax Act (Ontario) as modified by the Electricity Act, 1998, and related regulations.

PILs expense comprises current and deferred tax. Current tax and deferred tax are recognized in net income except to the extent that it relates to items recognized directly in equity or regulatory deferral account balances (See Note 3 (iii)).

8. Payments in Lieu of Taxes Payable (continued)

Significant judgment is required in determining the provision for PILs. There are many transactions and calculations undertaken during the ordinary course of business for which the ultimate tax determination is uncertain. The Corporation recognizes liabilities for anticipated tax audit issues based on the Corporation's current understanding of the tax law. Where the final tax outcome of these matters is different from the amounts that were initially recorded, such differences will impact the current and deferred tax provisions in the period in which such determination is made.

The significant components of the payments in lieu of taxes expense are as follows:

	2023	2022
Current tax		
Based on current year taxable income	$ (21,474)	$ 19,945

There is no tax effect from amounts recognized in other comprehensive income.

The income tax expense varies from amounts which would be computed by applying the Corporation's combined statutory income tax rate as follows:

	2023	2022
Total comprehensive income	$ 292,665	$ 136,297
Provision for payment in lieu of taxes	(21,474)	19,945
	271,191	156,242
Effective rate applied to income before provision for payments in lieu of taxes	26.50 %	26.50 %
Expected provision for payments in lieu of taxes	71,866	41,404
Increase (decrease) in income tax resulting from:		
Losses not recognized for tax	490	1,971
Items not deductible for tax purposes	49	268
Difference in asset tax bases included in regulatory deferral accounts as deferred tax	(7,514)	(22,750)
Other	(1,986)	(948)
	62,905	19,945
Rate adjustments		
Small business deduction	(38,781)	-
Small business deduction recovery from prior periods	(45,598)	-
Provision for payments in lieu of taxes	$ (21,474)	$ 19,945

The effective rate is calculated by dividing taxable income by the provision for payments in lieu of taxes. When there is no taxable income, the effective tax rate is estimated by combining the enacted Federal and Ontario general tax rates for the year.

8. Payments in Lieu of Taxes Payable (continued)

The movement in the 2023 deferred tax asset is:

	Opening balance at January 1	Change in asset base	Change in tax rate	Closing balance at December 31
2023				
Property, plant and equipment	$ (5,277)	$ (16,541)	$ 11,773	$ (10,045)
Contributions in aid of construction	81,085	452	(43,999)	37,538
Deferred tax asset	$ 75,808	$ (16,089)	$ (32,226)	$ 27,493
2022				
Property, plant and equipment	$ 42,190	$ (47,467)	$ -	$ (5,277)
Contributions in aid of construction	58,827	22,258	-	81,085
Deferred tax asset	$ 101,017	$ (25,209)	$ -	$ 75,808

At December 31, 2023, a deferred tax asset of $27,493 (2022 - $75,808) has been recorded. The utilization of this tax asset is dependent on future taxable profits arising from the reversal of existing taxable temporary differences. The Corporation believes that this asset should be recognized as it will be recovered through future rates.

9. Accounts Payable and Accrued Liabilities

Accounts payable and accrued liabilities are classified as measured at amortized cost. Major components of accounts payable and accrued liabilities consist of the following:

	2023	2022
Accounts payable and accruals	$ 423,046	$ 390,682
Contract liabilities	250,889	65,081
Government remittances payable	82,105	39,929
Other	54,310	57,794
	$ 810,350	$ 553,486

Contract liabilities consist of payments from large electricity customers received in advance of the delivery of electricity. The Corporation has an agreement in place requiring a minimum balance to be paid in advance, approximately equal to the next month's invoices.

9. Accounts Payable and Accrued Liabilities (continued)

The following table presents a summary of the activity related to the Corporation's contract liabilities.

	2023	2022
Contract liabilities, beginning of year	$ 65,081	$ 189,399
Revenue recognized during the year	(1,034,192)	(1,174,318)
Prepayments received	1,220,000	1,050,000
Contract liabilities, end of year	$ 250,889	$ 65,081

There were no contract modifications, changes in estimates or changes in the timing of revenue recognition during 2023 or 2022 impacting the contract liabilities balance.

10. Long-term Debt

Long-term debt is classified as measured at amortized cost and consists of the following:

	2023	2022
Due April 2025, monthly payments of $3,435 principal plus interest at prime, unsecured.	$ 54,963	$ 96,185
Due July 2025, monthly payments of $1,272 principal plus interest at prime, unsecured.	24,281	39,545
Due May 2023, monthly payments of $1,250 principal plus interest at prime, unsecured.	-	6,250
	79,244	141,980
Less current portion	56,486	62,736
	$ 22,758	$ 79,244

10. Long-term debt (continued)

Scheduled principal payments due on long-term debt in the next two years are as follows:

Year	Amount
2024	$ 56,486
2025	22,758
	$ 79,244

Since the interest rates are variable based on prime, the Corporation is exposed to interest rate risk. This is the risk that the future cash flows of the financial instruments will fluctuate because of changes in market interest rates. The Corporation structures its finances so as to stagger the maturities of debt, thereby minimizing exposure to interest rate fluctuations.

The Corporation is also exposed to liquidity risk as a result of holding long-term debt, which is the risk that the Corporation will not be able to meet its financial obligations as they come due. The Corporation monitors its liquidity risk to ensure access to sufficient funds to meet operational and investing requirements. The Corporation's objective is to ensure that sufficient liquidity is on hand to meet obligations as they fall due while minimizing interest exposure. The Corporation has access to a $500,000 credit facility and monitors cash balances to ensure that sufficient levels of liquidity are on hand to meet financial commitments as they come due.

11. Share Capital

a) Ordinary Shares

The authorized share capital is as follows:

Unlimited Class A Preferred shares, voting, redeemable at issue price and entitled to a non-cumulative dividend determined by the Board of Directors.

Unlimited Class B Preferred shares, voting, redeemable at issue price and entitled to a non-cumulative dividend determined by the Board of Directors.

Unlimited Class C Preferred shares, voting, redeemable at issue price and entitled to a non-cumulative dividend determined by the Board of Directors.

11. Share Capital (continued)

Unlimited Class D Preferred shares, non-voting, redeemable only at the option of the Corporation at issue price and entitled to a non-cumulative dividend determined by the Board of Directors.

Unlimited Class E Preferred shares, non-voting, redeemable at issue price and entitled to a non-cumulative dividend determined by the Board of Directors.

Unlimited Class A Common shares, voting, entitled to a non-cumulative dividend determined by the Board of Directors.

Unlimited Class B Common shares, voting, entitled to a non-cumulative dividend determined by the Board of Directors.

Unlimited Class C Common shares, non-voting, entitled to a non-cumulative dividend determined by the Board of Directors.

Unlimited Class D Common shares, non-voting, entitled to a non-cumulative dividend determined by the Board of Directors.

Unlimited Class E Common shares, non-voting, entitled to a non-cumulative dividend determined by the Board of Directors.

Issued

		2023	2022
1,262,063	Class D Preference shares	$ 1,262,063	$ 1,262,063
12,779	Class A Common shares	1,277,900	1,277,900
Total		$ 2,539,963	$ 2,539,963

12. Credit Facility

Atikokan Hydro Inc. is party to a short-term credit facility with a Canadian chartered bank pursuant to which the Corporation could borrow up to $500,000 in the form of an operating loan. The amount drawn under the credit facility as at December 31, 2023, was $NIL (2022 - $NIL).

13. Financial Guarantees

Participants in the wholesale market for electricity that is administered by the Independent Electricity Market Operator are required to satisfy prescribed prudential requirements.

The Corporation is party to an irrevocable standby letter of credit with a Canadian chartered bank. The credit amounts to $315,920 (2022 - $315,920) and has no contractual term. This letter of credit is secured by a general security agreement.

14. Related Party Transactions

The Ultimate Parent

The common shares of Atikokan Hydro Inc. are owned by the Corporation of the Town of Atikokan, the ultimate parent, which constitutes a local government. Consequently, the Corporation is exempt from some of the general disclosure requirements of IAS 24 with relation to transactions with government-related parties, and has applied the government-related disclosure requirements.

Transactions with Related Parties

The Corporation provides electricity and services to the Corporation of the Town of Atikokan.

	2023	2022
Sales to the Corporation of the Town of Atikokan	$ 710,633	$ 688,424

Atikokan Hydro Inc. and Atikokan Enercom Inc. are related due to common ownership. Atikokan Hydro Inc. provides electricity and other services to Atikokan Enercom Inc. as follows:

	2023	2022
Electricity sales	$ -	$ 541
Other sales	44,049	69,787
	$ 44,049	$ 70,328

Atikokan Hydro Inc. makes purchases and pays interest on long-term debt to Atikokan Enercom Inc. (Note 10) as follows:

	2023	2022
Interest on long-term debt	$ 7,645	$ 7,745
Other purchases	128	2,113
	$ 7,773	$ 9,858

The sales were recorded at fair market value and took place in the normal course of business.

Key Management Personnel Compensation Comprised:

The key management personnel of the Corporation has been defined as members of its Board of Directors.

	2023	2022
Directors' fees	$ 8,719	$ 8,614

15. Inventory

Cost of inventories comprise of direct materials, which typically consists of distribution assets not deemed as major spares, unless purchased for specific capital projects in process or as spare units. Costs, after deducting rebates and discounts, are assigned to individual items of inventory on the basis of weighted average cost. Decommissioned assets that are transferred to inventory are tested for impairment once they are removed from service and placed in inventory. Inventory is recognized at the lower of cost and net realizable value. The amount of inventories consumed by the Corporation and recognized as an expense or property, plant and equipment during 2023 was $92,102 (2022 - $49,636).

16. Expenses by Nature

	2023	2022
Repairs and maintenance	$ 85,425	$ 66,762
Staff costs	717,131	746,206
General administration and overhead	656,541	617,077
Bad debts	308	3,060
Energy cost	3,291,014	3,517,184
	$ 4,750,419	$ 4,950,289

17. Finance Income and Finance Cost

	2023	2022
Finance Income		
Recognized in profit or loss:		
Interest income on receivables	$ 7,429	$ 7,213
Other interest revenue	52,396	16,706
	$ 59,825	$ 23,919
Finance Cost		
Recognized in profit or loss:		
Interest on long-term debt	$ 7,645	$ 7,745
Other interest expense	22,446	6,910
	$ 30,091	$ 14,655

18. Employee Future Benefits

Defined Contribution Plan

The employees of the Corporation participate in the Ontario Municipal Employees Retirement System ("OMERS"), which is a multi-employer plan. The Corporation also makes contributions to the OMERS plan on behalf of its employees. The plan has a defined benefit option at retirement available to some employees, which specifies the amount of the retirement benefit plan to be received by the employees based on length of service and rates of pay. However, the plan is accounted for as a defined contribution plan as insufficient information is available to account for the plan as a defined benefit plan. The Corporation is only one of a number of employers that participates in the plan and the financial information provided to the Corporation on the basis of the contractual agreements is usually insufficient to reliably measure the Corporation's proportionate share in the plan assets and liabilities.

The contribution payable in exchange for services rendered during a period is recognized as an expense during that period. Contributions made by the Corporation to OMERS for 2023 were $65,613 (2022 - $64,394), representing less than 0.1% of total contributions to the OMERS plan. The contributions were made for current service and these have been recognized in net income.

Expected contributions to the plan for the next annual reporting period amount to $65,613, which is based on payments made to the multi-employer plan during the current fiscal year.

As at December 31, 2023, the OMERS plan was 97% funded (December 31, 2022 - 95%). OMERS has a strategy to return the plan to a fully funded position. The Corporation is not able to assess the implications, if any, of this strategy or of the withdrawal of other participating entities from the OMERS plan on its future contributions.

19. Capital Management

The main objectives of the Corporation, when managing capital, are to:

- Ensure ongoing access to funding to maintain, refurbish and expand the electricity distribution system;
- Ensure sufficient liquidity is available to meet the needs of the Corporation; and
- Provide appropriate financial returns to its shareholder.

The Corporation manages capital by monitoring forecasted cash flows and capital expenditures. The Corporation is not subject to any externally imposed capital requirements.

As at December 31, 2023, the Corporation's definition of capital is shareholder's equity. There have been no changes in what the Corporation considers to be capital since the previous period. As at December 31, 2023, shareholder's equity amounts to $3,959,272 (2022 - $3,666,607).

20. Standards, Amendments and Interpretations Not Yet Effective

There are a number of standards, amendments to standards, and interpretations which have been issued by the IASB that are effective in future accounting periods that the Corporation has decided not to adopt early.

The following amendments are effective for the period beginning January 1, 2024:

- Liability in a Sale and Leaseback (Amendments to IFRS 16 Leases);
- Classification of Liabilities as Current or Non-Current (Amendments to IAS 1 Presentation of Financial Statements);
- Non-current Liabilities with Covenants (Amendments to IAS 1 Presentation of Financial Statements); and
- Supplier Finance Arrangements (Amendments to IAS 7 Statement of Cash Flows and IFRS 7 Financial Instruments: Disclosures)

The following amendments are effective for the period beginning January 1, 2025:

- Lack of Exchangeability (Amendments to IAS 21 The Effects of Changes in Foreign Exchange Rates)

The Corporation is currently assessing the impact of these new accounting standards and amendments. The Corporation does not expect any standards issued by the IASB, but are yet to be effective, to have a material impact on the Corporation.