March 11, 2026

VIA RESS

Mr. Ritchie Murray
Acting Registrar
Ontario Energy Board
2300 Yonge Street
27th Floor, Box 2319
Toronto, ON M4P 1E4
Email: registrar@oeb.ca

Dear Mr. Murray;

RE: OEB File No. EB-2025-0252, Alectra Utilities Corporation ("Alectra Utilities") 2027-2031 Custom Rate Application for Electricity Distribution Rates and Charges (the "Application") – Alectra Utilities' Updated Evidence

Alectra Utilities Corporation ("Alectra") is the Applicant in the above-referenced proceeding. In accordance with the Ontario Energy Board's ("OEB") Procedural Order No. 1 dated December 12, 2025, the Applicant is filing certain financial information based on 2025 actual data.

Enclosed are the following financial information based on 2025 actual data:

- 2025 Alectra Utilities Corporation Audited Financial Statements
- 2025 Management's Discussion and Analysis
- Group 1 and Group 2 audited deferral and variance account (DVA) balances ending December 31, 2025 and updated DVA Continuity Schedules
- 2025 Reconciliation between audited financial statements and RRR
- 2025 Commodity Accounts Analysis Workform

This evidence update is being filed electronically through the OEB's RESS site. Included with the electronic filing are the following live Excel models:

- Attachment 1-15: 2025 Reconciliation between Audited & OEB Financial Statements
- Attachment 9-1: DVA Continuity Schedule HRZ Updated March 11
- Attachment 9-2: DVA Continuity Schedule BRZ Updated March 11
- Attachment 9-3: DVA Continuity Schedule PRZ Updated March 11
- Attachment 9-4: DVA Continuity Schedule ERZ Updated March 11
- Attachment 9-5: DVA Continuity Schedule GRZ Updated March 11
- Attachment 9-17: Commodity Accounts Analysis Workform HRZ
- Attachment 9-18: Commodity Accounts Analysis Workform BRZ

- Attachment 9-19: Commodity Accounts Analysis Workform PRZ
- Attachment 9-20: Commodity Accounts Analysis Workform ERZ
- Attachment 9-21: Commodity Accounts Analysis Workform GRZ

Should you have any questions or require additional information, please do not hesitate to contact the undersigned.

Yours truly,

Christine E. Long

Digitally signed by Christine E. Long
Date: 2026.03.11 15:34:21 -04'00'

Christine E. Long
Senior Vice-President Regulatory Affairs & Privacy Officer
Christine.Long@alectrautilities.com

cc: Charles Keizer, Torys LLP
All parties in EB-2025-0252

Attachment 1-13

2025 Audited Financial Statements

Consolidated Financial Statements
(In millions of Canadian dollars)

ALECTRA UTILITIES CORPORATION

Year ended December 31, 2025

KPMG LLP
100 New Park Place, Suite 1400
Vaughan, ON L4K 0J3
Canada
Tel 905 265 5900
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INDEPENDENT AUDITOR'S REPORT

To the Shareholders of Alectra Utilities Corporation

Opinion

We have audited the consolidated financial statements of Alectra Utilities Corporation (the Entity), which comprise:

- the consolidated statement of financial position as at December 31, 2025
- the consolidated statement of income and comprehensive income for the year then ended
- the consolidated statement of changes in equity for the year then ended
- the consolidated statement of cash flows for the year then ended
- and notes to the consolidated financial statements, including a summary of material accounting policy information

(Hereinafter referred to as the "financial statements").

In our opinion, the accompanying financial statements present fairly, in all material respects, the consolidated financial position of the Entity as at December 31, 2025, and its consolidated financial performance and its consolidated cash flows for the year then ended in accordance with IFRS Accounting 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 auditor's 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 the financial statements in accordance with IFRS Accounting 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 the 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.

- 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.

- Plan and perform the group audit to obtain sufficient appropriate audit evidence regarding the financial information of the entities or business units within the group as a basis for forming an opinion on the group financial statements. We are responsible for the direction, supervision and review of the audit work performed for the purposes of the group audit. We remain solely responsible for our audit opinion.

KPMG LLP

Chartered Professional Accountants, Licensed Public Accountants

Vaughan, Canada

March 5, 2026

ALECTRA UTILITIES CORPORATION

Consolidated Statement of Financial Position

(In millions of Canadian dollars)

as at December 31, 2025 and 2024

	Note	2025	2024
Assets			
Current assets			
Cash		13	45
Trade and other receivables	16	676	659
Other assets	8	83	86
Total current assets		**772**	**790**
Non-current assets			
Property, plant and equipment and right of use assets	6	4,820	4,490
Goodwill and other intangible assets	7	947	944
Other assets	8	4	4
Total non-current assets		**5,771**	**5,438**
Total assets		**6,543**	**6,228**
Liabilities and Shareholders' Equity			
Current liabilities			
Trade and other payables	9	509	460
Customer deposits liability		59	58
Deferred revenue	20	28	26
Lease obligations	15	2	2
Loans and borrowings	12	310	375
Other liabilities	11	89	98
Total current liabilities		**997**	**1,019**
Non-current liabilities			
Deferred revenue	20	946	808
Employee future benefits	13	72	74
Lease obligations	15	16	18
Loans and borrowings	12	2,277	2,278
Deferred tax liabilities	22	231	172
Other liabilities	11	36	34
Total non-current liabilities		**3,578**	**3,384**
Total liabilities		**4,575**	**4,403**
Shareholders' equity			
Share capital	14	704	707
Contributed surplus		826	826
Accumulated other comprehensive income		12	9
Retained earnings		426	283
Total shareholders' equity		**1,968**	**1,825**
Total liabilities and shareholders' equity		**6,543**	**6,228**

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

On behalf of the Board:

Director

Vinay Mehta

Director

ALECTRA UTILITIES CORPORATION

Consolidated Statement of Income and Comprehensive Income

(In millions of Canadian dollars)

for the years ended December 31, 2025 and 2024

	Notes	2025	2024
Revenue			
Distribution revenue	18	733	797
Electricity sales	18	3,622	3,306
Other revenue	18	82	78
		4,437	**4,181**
Expenses			
Cost of power		3,523	3,356
Operating expenses	19	332	314
Depreciation and amortization	6, 7	189	195
		4,044	**3,865**
Income from operating activities		**393**	**316**
Net finance costs	21	(98)	(102)
Net loss on derecognition of property, plant and equipment and intangible assets		(8)	(12)
Income before income taxes		**287**	**202**
Income tax expense	22	(76)	(54)
Net income		**211**	**148**
Other comprehensive income			
Items that will not be subsequently reclassified to income			
Remeasurement of defined benefit obligation	13	4	1
Tax impact on remeasurement of defined benefit obligation		(1)	—
Total other comprehensive income		**3**	**1**
Total comprehensive income		**214**	**149**

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

ALECTRA UTILITIES CORPORATION

Consolidated Statement of Changes in Equity
(In millions of Canadian dollars)

for the years ended December 31, 2025 and 2024

	Notes	Share capital	Contributed surplus	Accumulated other comprehensive income	Retained earnings	Total
Balance, January 1, 2024		719	826	8	202	1,755
Net income		—	—	—	148	148
Other comprehensive income		—	—	1	—	1
Return of capital	14, 24	(12)	—	—	10	(2)
Dividends paid	14, 24	—	—	—	(77)	(77)
Balance, December 31, 2024		**707**	**826**	**9**	**283**	**1,825**
Net income		—	—	—	211	211
Other comprehensive income		—	—	3	—	3
Return of capital	14, 24	(3)	—	—	—	(3)
Dividends paid	14, 24	—	—	—	(68)	(68)
Balance, December 31, 2025		**704**	**826**	**12**	**426**	**1,968**

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

ALECTRA UTILITIES CORPORATION

Consolidated Statement of Cash Flows
(In millions of Canadian dollars)

for the years ended December 31, 2025 and 2024

	Notes	2025	2024
Net cash from (used in)			
Operating activities			
Net income		211	148
Adjustments			
Depreciation and amortization	6, 7	189	195
Amortization and derecognition of capital contributions	20	(25)	(23)
Net loss on derecognition of property, plant and equipment and intangible assets		8	12
Net finance costs	21	98	102
Income tax expense	22	76	54
Net change in operating working capital	23	(2)	(95)
Net change in non-current assets and liabilities		3	8
Capital contributions received	20	148	109
Cash generated from operating activities		706	510
Income taxes paid	22	(21)	(11)
Income taxes refunded	22	1	1
Net cash from operating activities		**686**	**500**
Investing activities			
Purchase of property, plant and equipment	6	(459)	(438)
Purchase of intangible assets	7	(21)	(23)
Proceeds from disposal of property, plant and equipment and intangible assets		1	1
Net cash used in investing activities		**(479)**	**(460)**
Financing activities			
Repayment of loans and borrowings	12, 24	(11,627)	(12,570)
Proceeds from issuance in loans and borrowings, net of transaction costs	12, 24	11,558	12,765
Repayment of lease obligations	15, 24	(2)	(1)
Interest received	24	6	6
Interest paid	24	(103)	(108)
Return of capital	14, 24	(3)	(2)
Dividends paid	14, 24	(68)	(77)
Net cash (used in) from financing activities		**(239)**	**13**
Net cash (outflow) inflow		**(32)**	**53**
Cash (bank indebtedness), beginning of year		**45**	**(8)**
Cash, end of year		**13**	**45**

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

1. Description of the Business

Alectra Utilities Corporation (the "Corporation") is wholly-owned by Alectra Inc. and its registered head office is located at 55 John Street North, Hamilton, Ontario, Canada. The principal activity of the Corporation is to distribute electricity to customers in municipalities in the greater golden horseshoe area.

The accompanying consolidated financial statements of the Corporation include the accounts of the Corporation and its 99% ownership interest in Solar Sunbelt General Partnership ("Solar Sunbelt GP"), which has been established to undertake a solar generation business. The principal solar divisions of the Corporation are: Ring Fenced Solar Portfolio ("RFSP"), a solar generation business within the Corporation; and Solar Sunbelt GP. The Corporation is also the managing partner of Solar Sunbelt GP.

2. Basis of Preparation

(a) Statement of compliance

These consolidated financial statements have been prepared in accordance with IFRS Accounting Standards ("IFRS"), as issued by the International Accounting Standards Board ("IASB"). These consolidated financial statements were approved by the Board of Directors on March 5, 2026.

Certain prior year figures have been reclassified to conform to the presentation of the current year.

(b) Functional and presentation currency, and basis of measurement

These consolidated financial statements are presented in Canadian dollars ("$CAD"), which is the functional currency of the Corporation. These consolidated financial statements have been prepared on a historical cost basis, except for the valuation of employee future benefits, which are recorded at the actuarial present value of the defined benefit obligation. Amounts are rounded to the nearest million, unless otherwise stated.

(c) Use of estimates and judgments

The preparation of the consolidated financial statements in conformity with IFRS requires management to make judgments and estimates that affect the application of accounting policies and the amounts reported and disclosed in these consolidated financial statements.

Estimates are used predominately in determining the measurement of certain of the Corporation's assets and liabilities. Estimates and underlying assumptions are continually reviewed and are based on factors that are considered to be relevant, such as historical experience and forecast trends. Actual results may differ from these estimates. Revisions of estimates are recognized in the period of revision and prospectively.

The areas which require management to make significant estimates and assumptions are as follows:

- Note 4(b)(i) – recognition and measurement of unbilled revenue;
- Note 4(c) – estimation of the fair value for financial assets and liabilities;
- Note 4(e) and (f) – estimation of the useful lives of property, plant and equipment and finite life intangible assets;
- Note 4(g) – impairment of non-financial assets: key assumptions underlying recoverable amounts; and
- Note 4(i) – measurement of employee future benefits – key actuarial assumptions.

Judgments included in the consolidated financial statements are decisions made by management, based on the analysis of relevant information available at the time of each decision. Judgments relate to the application of accounting policies and decisions related to the recognition, measurement and disclosure of financial amounts.

2. Basis of Preparation (continued)

(c) Use of estimates and judgments (continued)

The areas which require management to make significant judgments are as follows:

- Note 4(b)(i) – principal versus agent determination for recording revenue on a gross or net basis;
- Note 4(b)(ii) – deferred revenue: assessment of the performance obligation for contributions from customer;
- Note 4(h) – recognition and measurement of provisions and contingencies, determining whether a present obligation exists and assessing the probability, timing, and amount of any future outflows; and
- Note 4(k) – recognition of deferred tax assets and liabilities.

Changes in the economic environment arising from geopolitical events and uncertainty over economic growth could generate, in future periods, a risk of adjustments to the carrying amounts of balances subject to estimates and judgments.

3. Regulation

The Corporation is regulated by the Ontario Energy Board ("OEB"). In its capacity to approve or set rates, the OEB has the authority to specify regulatory accounting treatments that differ from IFRS. The regulatory accounting treatments of the OEB require the recognition of regulatory assets and liabilities which do not meet the definition of an asset or liability under IFRS. Refer to Note 26.

(a) Rate Setting

The electricity distribution rates and other regulated charges of the Corporation are determined in a manner that provides the shareholders of Alectra Inc. with opportunity to earn a regulated maximum allowable return on equity ("MARE") on the amount of shareholders' equity supporting the business of electricity distribution, which is also determined by regulation.

The rate-making policies of the OEB are guided by its statutory objectives under *The Ontario Energy Board Act, 1998 (Ontario)* that include, among other matters, to support the cost-effective planning and operation of the electricity distribution network and to provide an appropriate alignment between a sustainable, financially viable electricity sector and the expectations of customers for reliable service at a reasonable price.

The OEB regulates the electricity distribution rates charged by local distribution companies ("LDCs"), such as the Corporation, through periodic rate applications to the OEB and its ongoing monitoring and reporting requirements. At present, LDCs may apply to the OEB for electricity distribution rates under options specified in its *Report of the Board - A Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach* (“RRF”). The three rate-setting methods available to LDCs under the RRF are Price Cap Incentive Rate-setting (“Price Cap IR”), Custom Incentive Rate-setting ("Custom IR"), or Annual Incentive Rate-setting Index ("Annual IR").

Price Cap IR

The Price Cap IR method establishes rates on a single forward test-year cost of service basis, indexed for four subsequent years through a formulaic adjustment.

3. Regulation (continued)

(a) Rate Setting (continued)

Price Cap IR (continued)

The Incremental Capital Module ("ICM") is available to distributors under the Price Cap IR method. It is intended to address capital investment needs that arise during the rate-setting plan that are incremental to an OEB prescribed materiality threshold. The requested amount for an ICM claim must be: incremental to a distributor's capital requirements within the context of its financial capacities underpinned by existing rates; and satisfy the eligibility criteria of materiality, need, and prudence. For distributors that are in an extended rebasing deferral period arising from utility consolidations (i.e., distributors in years six to ten of the rebasing deferral period), incremental capital funding may be requested for an annual capital program. The OEB requires that a distributor requesting relief for incremental capital during the Price Cap IR plan term include comprehensive evidence to support the need. This includes the calculation of a rate rider to recover the incremental revenue from each applicable customer class. The incremental revenue is recognized in the year when the actual ICM related expenditures are expected to be in-service. This approach is consistent with the timing of the actual capital investment benefit to customers, which aligns with the expected timing of the OEB approval of ICM rate adjustments.

Custom IR

The Custom IR method establishes rates based on a forecast of an LDC's revenue requirement and sales volumes. This rate-setting method is customized to fit the specific applicant's circumstances. The annual rate adjustment over the Custom IR term is determined by the OEB on a case-by-case basis.

Annual IR

The Annual IR method sets a distributor's rates through an annual adjustment mechanism.

(b) Rate Applications

2025 Rate Application

On August 15, 2024, the Corporation filed an application for all five predecessor utility rate zones for the approval of 2025 electricity distribution rates and other charges, effective January 1, 2025. On December 12, 2024, the OEB issued its Decision and Rate Order on the Price Cap IR application, approving a 3.3% rate adjustment to distribution rates effective January 1, 2025, and providing for disposition of deferral and variance account balances.

2026 Rate Application

On August 14, 2025, the Corporation filed an application for all five predecessor utility rate zones for the approval of 2026 electricity distribution rates and other charges, effective January 1, 2026. On December 16, 2025, the OEB issued its Decision and Rate Order on the Price Cap IR application, approving a 3.4% rate adjustment to distribution rates effective January 1, 2026, and providing for disposition of deferral and variance account balances.

2027 - 2031 Rate Application

On October 14, 2025, the Corporation filed a Custom IR application with the OEB seeking approval of electricity distribution rates and charges effective January 1, 2027. The application also includes proposed subsequent annual rate adjustments based on a custom price cap index for the period from January 1, 2028 to December 31, 2031. A decision from the OEB is expected in the fourth quarter of 2026.

4. Material Accounting Policies

The following material accounting policies used in the preparation of these consolidated financial statements, have been applied consistently to all periods presented herein;

(a) Basis of consolidation

These consolidated financial statements include the accounts of the Corporation and its subsidiaries from the date that control commences until the date that control ceases. The Corporation controls a subsidiary if it is exposed, or has rights, to variable returns from its investment in the subsidiary and can affect those returns through its power over the subsidiary. All intercompany accounts and transactions are eliminated on consolidation.

(b) Revenue from contracts with customers

Revenue is recognized at a point in time or over time, depending on when the Corporation has satisfied its performance obligation(s) to its customers. Where the Corporation has a right to consideration from a customer in an amount that corresponds directly with the value to the customer of the performance to date, revenue is recognized in an amount to which the Corporation has a "right to invoice". The right to invoice represents the fair value of the consideration received or receivable.

The following provides a summary of the nature of the various performance obligations within contracts with customers and when performance is recognized on those obligations:

(i) Distribution revenue and electricity sales

The Corporation has identified that its material performance obligation is the distribution and provision of electricity to customers. The Corporation is licensed by the OEB to distribute electricity. Distribution revenue is recognized based on OEB-approved distribution rates, set at a level intended to recover the costs incurred by the Corporation in delivering electricity to customers and a regulated return on invested capital, and includes revenue collected through OEB-approved rate riders. 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 it is acting as a principal for electricity distribution and therefore has presented the electricity sales on a gross basis. Revenue attributable to the delivery of electricity is based upon OEB-approved distribution tariff rates and includes the amounts billed to customers for electricity, including the cost of electricity supplied, distribution charges, and any other regulatory charges. Revenue is recognized as electricity is delivered and consumed by customers. Electricity sales are recorded based on regular meter readings and estimates of customer usage since the last meter reading date to the end of the year. The Corporation satisfies its performance obligation to the customer over time, which is to use reasonable diligence in providing a regular and uninterrupted supply of electricity over the contract term.

The measurement of unbilled revenue is based on an estimate of the amount of electricity delivered to customers but not yet billed. These accrued amounts are presented as unbilled revenues under IFRS 15, *Revenue from Contracts with Customers.* The Corporation assesses unbilled revenue for impairment in accordance with IFRS 9, *Financial Instruments.*

4. Material Accounting Policies (continued)

(b) Revenue from contracts with customers (continued)

(ii) Other revenue

Other revenue includes revenue from renewable generation, contributions from customers, and other general revenue. The methods of recognition for other revenue are as follows:

- Revenue from renewable generation sources is recognized in the period in which electricity is generated and delivered, based on regular meter readings, and is measured at the fair value of the consideration received or receivable, net of sales tax.
- Capital contributions received from electricity customers and developers to construct or acquire property, plant and equipment for the purpose of connecting a customer to a network are recorded as deferred revenue. The deferred revenue is initially recorded at fair value of the capital contribution and amortized to other revenue on a straight-line basis over the estimated economic lives of the assets to which the contribution relates. Contributions received from customers to construct or acquire fixed assets to deliver services other than those related to delivery of electricity are recorded as deferred revenue and amortized to other revenue over the term of the contract with the customer.
- Revenue is recognized as services are rendered for activities ancillary to electricity distribution, including street lighting services, water billing, and pole and duct rentals.

(c) Financial instruments

Financial assets and liabilities include cash, trade and other receivables, trade and other payables, customer deposits liability, and loans and borrowings. All financial assets and liabilities, except trade and other receivables, are initially recognized at fair value plus transaction costs. Trade and other receivables balances are initially recognized at the transaction price. Financial assets and liabilities are subsequently measured at amortized cost using the effective interest rate method, less any applicable impairment. Interest income is calculated using the effective interest rate method and is recognized in the Consolidated Statement of Income and Comprehensive Income.

Impairment of the Corporation’s financial assets is assessed on a forward-looking basis. The Corporation applies the simplified approach to its trade receivables which requires expected lifetime losses to be recognized from initial recognition of the receivables and on an ongoing basis. The Corporation assesses all information available in the measurement of the expected credit losses ("ECL") associated with its assets carried at amortized cost.

The measurement of ECL for trade receivables is based on management's estimates and assumptions. ECL is determined using a provision matrix based on historical observed default rates and incorporated macroeconomic factors such as GDP growth forecast, inflation rates, unemployment rates, and customer-specific assessments. Trade receivables are written-off against the allowance when they are deemed uncollectible.

(d) Inventories

Inventories are valued at the lower of cost and net realizable value. Cost is determined on a weighted-moving average basis and includes expenditures incurred in acquiring the inventories and other costs to bring the inventories to their existing location and condition.

4. Material Accounting Policies (continued)

(e) Property, plant and equipment ("PP&E")

Land is measured at cost. PP&E (other than land) is measured at cost less accumulated depreciation and accumulated impairment losses. Cost includes expenditures that are directly attributable to the acquisition of the asset and includes contracted services, cost of materials, directly attributable overhead, direct labour, pension and other benefit costs, and borrowing costs incurred in respect of qualifying assets constructed.

Work in progress assets are generally assets that are undergoing active construction or development and are not currently available for use. Work in progress assets are not depreciated.

When items of PP&E are disposed of, a gain or loss on asset derecognition, if any, is determined by comparing the proceeds from disposal with the carrying amount of the item. Any gain or loss on asset derecognition is included in the Consolidated Statement of Income and Comprehensive Income.

Depreciation of PP&E is recognized on a straight-line basis over the useful life of each item. Depreciation on these assets commences when such assets are ready for their intended use.

The assessment of the useful lives of PP&E is based on management's judgment and are reviewed at each financial year-end and adjusted prospectively. When components of an item of PP&E have different useful lives, each component is recorded separately within PP&E and depreciated over each component's useful life. These assets are classified to the appropriate categories of PP&E when completed and ready for intended use.

The method of depreciation and estimated useful lives for each category of PP&E are as follows:

Buildings	Straight-line	10 to 60 years
Distribution assets	Straight-line	10 to 70 years
Other assets	Straight-line	4 to 20 years

(f) Goodwill and other intangible assets

Intangible assets include goodwill, land rights, computer software, and contributions.

Goodwill arising on the acquisition of subsidiaries or on amalgamation represents the excess of the purchase price over the fair value assigned to the Corporation's interest of the net identifiable assets acquired. Goodwill is measured at cost less accumulated impairment losses.

Land rights are measured at cost. Land rights held by the Corporation are effective in perpetuity and there is no foreseeable limit to the period over which the rights are expected to provide benefit to the Corporation. Consequently, no removal date can be determined and no reasonable estimate of the fair value of such asset retirement obligations can be determined. If, at some future date, it becomes possible to estimate the fair value cost of removing these assets and the Corporation is legally or constructively required to remove such assets, a related asset retirement obligation will be recognized at that time. Land rights have been assessed as having an indefinite useful life.

Computer software is measured at cost less accumulated amortization and any applicable impairment losses. Amortization begins when the asset is available for use and is measured on a straight-line basis.

4. Material Accounting Policies (continued)

(f) Goodwill and other intangible assets (continued)

Contributions represent payments made to Hydro One Networks Inc. ("Hydro One"), an electricity distributor and transmitter in the Province of Ontario, for building dedicated infrastructure to accommodate the Corporation's distribution system requirements. Contributions are measured at cost less accumulated amortization.

Work in progress assets are generally assets that are undergoing development and are not currently available for use. Work in progress assets are not depreciated.

Gains or losses arising from derecognition, if any, of an intangible asset are measured as the difference between the net proceeds from disposal and the carrying amount of the asset and are recognized in the Consolidated Statement of Income and Comprehensive Income when the asset is derecognized.

The useful lives of intangible assets are assessed based on management's judgment and are reviewed at each financial year-end and adjusted prospectively. The useful lives and amortization methods are as follows:

Goodwill	Not amortized	Indefinite
Land rights	Not amortized	Indefinite
Computer software	Straight-line	4 to 15 years
Contributions	Straight-line	10 to 70 years

(g) Impairment of non-financial assets

For the purpose of impairment testing, the Corporation uses judgment to categorize its assets into the smallest group that generates cash inflows that are largely independent of cash inflows from other assets or cash generating units ("CGU"). Goodwill acquired in a business combination is allocated to groups of CGUs that are expected to benefit from the synergies of the combination.

Intangible assets with indefinite lives (including goodwill) are tested for impairment annually and when circumstances indicate that the recoverable amount of an asset or CGU may be below its carrying value. The recoverable amount of an asset or CGU is the greater of its value in use and fair value less costs of disposal. The value in use calculation requires an estimate of the future cash flows expected to arise from the CGU, a suitable discount rate in order to calculate a present value as a basis for determining impairment and an estimated terminal value calculated by discounting the final year in perpetuity. Fair value less costs of disposal is determined based on observable market inputs and categorized as level 2 for fair value measurement.

Impairment losses are recognized if the carrying amount of an asset or CGU exceeds its recoverable amount, and are recognized in the Consolidated Statement of Income and Comprehensive Income. Impairment losses relating to CGUs are allocated first to reduce the carrying amount of any goodwill allocated to the CGUs and then to reduce the carrying amounts of the other assets in the CGUs on a pro rata basis.

An impairment loss in respect of goodwill is not reversed. In respect of other assets, an impairment loss is reversed only to the extent that the carrying amount of the asset does not exceed the carrying amount that would have been determined, net of depreciation or amortization, as if no impairment loss had been previously recognized.

4. Material Accounting Policies (continued)

(h) Provisions and contingencies

A provision is recognized if, as a result of a past event, the Corporation has a present legal or constructive obligation that can be determined reliably, and it is probable that an outflow of economic benefits will be required to settle the obligation. Provisions are measured as the expected outcome of the consideration required to settle the present obligation at the reporting date. Significant judgement is required in determining whether a present obligation exists and its probability of realization. Provisions are subject to significant uncertainty and are determined by discounting the expected future cash flows at a rate, net of tax, that corresponds to current market assessments of the time value of money and the risks specific to the liability. The increase in the provision due to the passage of time is recognized as an expense.

Decommissioning provisions are liabilities recognized in the consolidated financial statements for the future costs associated with dismantling and removing assets, and restoring the site to its original condition. The estimated future cash flows of the site restoration costs are risk adjusted and discounted using a rate that reflects current market assessment of the time value of money and the risk specific to the project. The associated site restoration costs are capitalized as part of the carrying amount of the asset and are amortized over the asset's useful life. Changes due to revision of discount rates, the timing, or the amount of the original estimate of the provision are reflected on a prospective basis by adjusting the carrying amount of the related asset. In the event the amounts resulting from the changes in estimates exceed the carrying amount of the related asset, the excess amount is recognized immediately in the Consolidated Statement of Income and Comprehensive Income.

Contingencies are disclosed unless the possibility of an outflow of economic benefits is remote.

An assessment of the likelihood of a contingent event, such as events arising from legal proceedings, third-party contracts and other events, requires management's judgment as to the probability of a loss occurring. Actual results may differ from those estimates.

(i) Employee future benefits

The Corporation provides pension and other benefit plans for its employees. Details on these plans are as follows:

(i) Multi-employer defined benefit pension plan

The Corporation provides a pension plan for all of its full-time employees through Ontario Municipal Employees Retirement System ("OMERS"). OMERS is a multi-employer pension plan which operates as the Ontario Municipal Employees Retirement Fund ("the Fund") and provides pensions for employees of Ontario municipalities, local boards, public utilities, and school boards. The Fund is a contributory defined benefit pension plan, which is financed by equal contributions from participating employers and employees, and by the investment earnings of the Fund.

As OMERS does not segregate its pension asset and liability information by individual employers, there is insufficient information available to enable the Corporation to directly account for the plan as a defined benefit plan. Consequently, the plan has been accounted for as a defined contribution plan. Obligations for contributions to defined contribution pension plans are recognized as an employee benefit expense in the Consolidated Statement of Income and Comprehensive Income when they are due.

4. Material Accounting Policies (continued)

(i) Employee future benefits (continued)

(ii) Non-pension defined benefit plans

The Corporation provides some of its retired employees with life insurance and medical benefits beyond those provided by government sponsored plans. These benefits are provided through group defined benefit plans shared between entities under common control of Alectra Inc. The Corporation, which is controlled by Alectra Inc., is the legal sponsor of the plans. There is a stated policy in place to allocate the net defined benefit cost to the participating entities under the common control of Alectra Inc. based on the obligation attributable to the plan participants employed by each participating entity.

The Corporation has incorporated its share of the defined benefit costs and related liabilities, as calculated by the actuary, in these consolidated financial statements.

The Corporation's net obligation in respect of defined benefit plans is calculated separately for each plan by estimating the amount of future benefit that employees have earned in return for their service in the current and prior periods and discounting such to determine its present value. The discount rate is the interest yield, at the reporting date, on high quality debt instruments with duration similar to the duration of the plan. Due to the long-term nature of these plans, estimates used in the valuation such as discount rates, expected rates of return on assets, future salary increases and mortality rates, are subject to significant uncertainty.

The cost of these benefits is expensed as earned by employees through employment service. The accrued benefit obligation and the current service costs are actuarially determined by applying the projected unit credit method and incorporate management's best estimate of certain underlying assumptions. Remeasurements arising from defined benefit plans are recognized immediately in other comprehensive income and reported in accumulated other comprehensive income. Amounts recorded in Other Comprehensive Income ("OCI") are not reclassified to the Consolidated Statement of Income and Comprehensive Income.

The measurement date used to determine the present value of the benefit obligation is December 31 of the applicable year. The latest full actuarial valuation was performed as at December 31, 2025.

(j) Customer deposits liability

Customer deposit liability is comprised of cash collections from customers as security for the payment of energy bills and water bills. Deposits held in respect of commercial customers are applied against any unpaid portion of individual customer accounts. Customer deposit liability in excess of unpaid account balances is refundable to individual customers upon termination of their electricity distribution service. These customer deposits are classified as a current liability as they are refundable on demand once a customer establishes a good payment history in accordance with the policies of the Corporation. This liability includes related interest amounts owed to the customers with a corresponding amount charged to finance costs.

4. Material Accounting Policies (continued)

(k) Income taxes

The Corporation is exempt from income taxes under the Income Tax Act (Canada) and the Ontario Corporations Tax Act (collectively, the 'Tax Acts'). Accordingly, the Corporation is required to make payments in lieu of income taxes ('PILs') to the Ontario Electricity Finance Corporation ('OEFC'), which are calculated in accordance with the Tax Acts and applied to reduce certain debt obligations of the former Ontario Hydro continuing in OEFC.

PILs comprise current and deferred payments in lieu of income tax. PILs is recognized in the Consolidated Statement of Income and Comprehensive Income except to the extent that it relates to items recognized directly in either comprehensive income or in equity, in which case, it is recognized in comprehensive income or in equity.

Current PILs is the expected amount of cash taxes payable on the taxable income for the year, using tax rates enacted or substantively enacted at the reporting date, and any adjustment to tax payable in respect of previous years.

Deferred PILs comprise the net tax effects of temporary differences between the tax basis of assets and liabilities and their respective carrying amounts for accounting purposes, as well as for tax losses available to be carried forward to future years that are likely to be realized. Deferred PILs assets and liabilities are measured using enacted or substantively enacted tax rates, at the reporting date, expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on deferred PILs assets and liabilities of a change in tax rates is recognized in income in the year that includes the date of enactment or substantive enactment.

A deferred PILs asset is recognized to the extent that it is probable that future taxable income will be available against which the temporary difference can be utilized. Deferred PILs assets are reviewed at each reporting date and are reduced to the extent that it is no longer probable that the related tax benefit will be realized.

(l) Finance income and costs

Finance income is recognized as it accrues in the Consolidated Statement of Income and Comprehensive Income and is comprised of interest earned on cash.

Finance costs comprise interest expense on borrowings, lease obligations and decommissioning provisions are recognized as an expense in the Consolidated Statement of Income and Comprehensive Income except for those amounts capitalized as part of the cost of qualifying property, plant and equipment.

(m) Advance payments

Advance payments are prepayments on capital projects that have been purchased and will remain as an advance until the project is in service and billable under the terms of the corresponding service agreements.

5. Future Accounting Changes

The following amendments and new standards have been published by the IASB but are not effective as at December 31, 2025, and have not been adopted in these consolidated financial statements.

Effective Date: Reporting periods beginning on or after January 1, 2026

(a) Amendments to the Classification and Measurement of Financial Instruments – Amendments to IFRS 9 Financial Instruments and IFRS 7 Financial Instruments: Disclosures

The amendments permit an entity to deem a financial liability (or part of it) that will be settled in cash using an electronic payment system to be discharged before the settlement date if specified criteria are met. An entity that elects to apply the derecognition option would be required to apply it to all settlements made through the same electronic payment system. For financial asset classification, the amendments offer clarity on assessing basic lending arrangements, provide a comprehensive description of non-recourse features, and detail contractually linked instruments. Additionally, disclosure requirements now include the fair value gain or loss from equity investments and contractual terms affecting cash flows.

These amendments are not expected to materially affect the consolidated financial statements as the Corporation holds no significant financial instruments whose treatment or disclosure would be affected.

Effective Date: Reporting periods beginning on or after January 1, 2027

(b) IFRS 18 Presentation and Disclosure in Financial Statements

In 2024, the IASB published a new IFRS accounting standard, IFRS 18 - *Presentation and Disclosure in Financial Statements*, to replace IAS 1, *Presentation of Financial Statements*, and will amend IAS 7, *Statement of Cash Flows*. The primary objective of IFRS 18 is to improve the assessment of an entity's performance by increasing comparability in presentation. Changes include introducing a defined structure for the presentation of the Consolidated Statement of Income and Comprehensive Income, including required totals and sub-totals, management-defined performance measures, enhanced requirements for grouping (aggregation and disaggregation) of information, and disclosure of specific expenses by nature.

The Corporation anticipates that implementation of the Standard will have a significant impact on the presentation and disclosures in its consolidated financial statements. The Corporation does not intend to early adopt the standard.

(c) IFRS 19 Subsidiaries without Public Accountability: Disclosures

IFRS 19 allows eligible subsidiaries to apply reduced disclosure requirements in its consolidated, separate or individual financial statements. This new standard aims to simplify and reduce the cost of financial reporting for subsidiaries while maintaining the usefulness of their financial statements.

The Corporation anticipates that implementation of the Standard will not have a significant impact on the presentation and disclosures in its consolidated financial statements.

(In millions of Canadian dollars)

6. Property, Plant and Equipment and Right of Use Assets

	Property, Plant and Equipment					RoU	
	Land and buildings	Distribution assets	Other assets	Work in progress	Total PP&E	RoU assets	Total PP&E & RoU
Cost							
Balance at January 1, 2024	328	4,579	250	154	5,311	24	5,335
Additions	—	—	—	470	470	2	472
Transfers into service	4	440	20	(464)	—	—	—
Disposals and write-offs	—	(20)	(11)	—	(31)	—	(31)
Balance at December 31, 2024	332	4,999	259	160	5,750	26	5,776
Additions	—	—	—	515	515	—	515
Transfers into service	5	498	14	(517)	—	—	—
Disposals and write-offs	—	(15)	(10)	—	(25)	—	(25)
Balance at December 31, 2025	337	5,482	263	158	6,240	26	6,266
Accumulated depreciation							
Balance at January 1, 2024	41	950	131	—	1,122	9	1,131
Depreciation	7	143	20	—	170	3	173
Disposals and write-offs	—	(7)	(11)	—	(18)	—	(18)
Balance at December 31, 2024	48	1,086	140	—	1,274	12	1,286
Depreciation	7	147	20	—	174	2	176
Disposals and write-offs	—	(6)	(10)	—	(16)	—	(16)
Balance at December 31, 2025	55	1,227	150	—	1,432	14	1,446
Net book value							
December 31, 2024	284	3,913	119	160	4,476	14	4,490
December 31, 2025	282	4,255	113	158	4,808	12	4,820

Other assets include solar panels, meters, vehicles, furniture and equipment, computer equipment, and leasehold improvements.

Effective January 1, 2025, the Corporation revised the estimated useful lives of its PP&E based on a study performed by an independent third party. This change was applied prospectively and will impact the depreciation expense for the year-ended December 31, 2025 and future years. The effect of the change on actual and expected depreciation expenses was as follows:

	2025	2026	2027	2028	2029	After 2029
(Decrease) increase in depreciation expense	(7)	(12)	(13)	(12)	(12)	56

Right of use ("RoU") assets represent the Corporation's right to use buildings and roof tops over the duration of the lease term.

(In millions of Canadian dollars)

6. Property, Plant and Equipment and Right of Use Assets (continued)

During the year, borrowing costs of $3 (2024 - $3) were capitalized as part of the cost of property plant & equipment and intangible assets. An average capitalization rate of 3.93% (2024 - 4.25%) was used to determine the amount of borrowing costs to be capitalized with respect to the Corporation. Refer to Note 21.

Reconciliation between the amounts presented on the Consolidated Statement of Cash Flows and additions to property, plant and equipment:

	Note	2025	2024
Purchase of property, plant and equipment, cash basis		459	438
Non-cash asset contributions	20	34	13
Depreciation expense capitalized		6	6
Borrowing cost capitalized	21	3	3
Adjustment for accruals		13	10
Additions to property, plant and equipment		515	470

Reconciliation between depreciation and amortization amounts included in continuity tables of Note 6 and 7 and the amounts presented on the Consolidated Statement of Income and Comprehensive Income:

	Note	2025	2024
Depreciation of property, plant and equipment and right of use assets	6	176	173
Amortization of intangible assets	7	19	28
Depreciation expense capitalized		(6)	(6)
Depreciation and amortization per Consolidated Statement of Income and Comprehensive Income		189	195

(In millions of Canadian dollars)

7. Goodwill and Other Intangible Assets

(a) Goodwill and other intangible assets

	Goodwill	Land rights	Computer software	Contributions	Work in progress	Total
Cost or deemed cost						
Balance at January 1, 2024	755	4	198	97	16	1,070
Additions	—	—	—	—	21	21
Transfers into service	—	—	27	—	(27)	—
Write-offs	—	—	(1)	—	—	(1)
Balance at December 31, 2024	755	4	224	97	10	1,090
Additions	—	—	—	—	22	22
Transfers into service	—	—	18	—	(18)	—
Disposals and write-offs	—	—	(6)	—	—	(6)
Balance at December 31, 2025	755	4	236	97	14	1,106
Accumulated amortization						
Balance at January 1, 2024	—	—	93	26	—	119
Amortization	—	—	25	3	—	28
Write-offs	—	—	(1)	—	—	(1)
Balance at December 31, 2024	—	—	117	29	—	146
Amortization	—	—	16	3	—	19
Disposals and write-offs	—	—	(6)	—	—	(6)
Balance at December 31, 2025	—	—	127	32	—	159
Net book value						
December 31, 2024	755	4	107	68	10	944
December 31, 2025	755	4	109	65	14	947

Included in work in progress is a refund of $3 (2024 - $nil) received from Hydro One Networks related to contributions resulting from the revision of estimates based on OEB-prescribed methodologies.

Effective January 1, 2025, the Corporation revised the estimated useful lives of its definite life intangible assets based on a study performed by an independent third party. This change was applied prospectively and will impact the amortization expense for the year-ended December 31, 2025 and future years. The effect of the change on actual and expected amortization expense was as follows:

	2025	2026	2027	2028	2029	After 2029
(Decrease) increase in amortization expense	(11)	(12)	(12)	3	5	27

Borrowing costs capitalized in intangible assets and property plant & equipment during the year is included in Note 6 and 21.

(In millions of Canadian dollars)

7. Goodwill and Other Intangible Assets (continued)

(a) Goodwill and other intangible assets (continued)

Reconciliation between the amounts presented on the Consolidated Statement of Cash Flows and additions to intangible assets:

	2025	2024
Purchase of intangible assets, cash basis	21	23
Adjustment for accruals	1	(2)
Additions to intangible assets	22	21

(b) Impairment testing of goodwill and other indefinite life intangible assets

Goodwill with a carrying amount of $755 (2024 - $755) and land rights with a carrying amount of $4 (2024 - $4) have been allocated to the Corporation's CGU. The Corporation tested goodwill and land rights for impairment as at September 30, 2025 and 2024, and determined that no impairment existed. The impairment test was performed by considering the latest developments and economic conditions. The recoverable amount of goodwill and land rights determined in the analysis for both years was greater than the carrying value and no impairment was recorded.

The recoverable amount of the CGUs is based on value-in-use calculations, which combines cash flow projections from the financial plan and extrapolated cash flows using terminal growth value.

The key assumptions used in the value-in-use calculations include forecast earnings before interest, taxes, depreciation, and amortization ("EBITDA"), weighted average cost of capital ("WACC") and a terminal growth value. Forecast EBITDA is based on expectations of future outcomes considering past experience and adjusted for anticipated revenue growth and cost savings.

The terminal growth value is projected using a rate base multiple of 1.3x (2024 - 1.3x). The WACC of 4.98% (2024 - 4.92%) is based on market and equity risk factors for comparable companies. Reasonable negative changes in any one key assumption, holding other factors constant, would not result in an impairment.

There were no significant changes to the key assumptions as at December 31, 2025 and 2024.

8. Other Assets

	2025	2024
Current		
Inventories	70	73
Prepaid expenses	13	11
Other receivable	—	2
	83	86
Non-Current		
Prepaid expenses	3	3
Other	1	1
	4	4

Inventories consist of parts and supplies acquired for internal construction or consumption.

(In millions of Canadian dollars)

9. Trade and Other Payables

	Note	2025	2024
Trade payables - energy purchases		279	254
Due to related parties	10	79	74
Accrued liabilities		80	68
Trade payables - other		43	36
Customer receivables in credit balances		28	28
		509	460

10. Related Party Balances and Transactions

(a) Balances and transactions with related parties

The Corporation provides services to and receives services from Alectra Inc. and Alectra Energy Solutions Inc. These services generally include administrative support such as information technology, finance, human resources and other services. Expenses with Alectra Inc. also include interest expense on the unsecured outstanding loan.

The cities of Mississauga, Vaughan, Hamilton, Markham, Barrie, St. Catharines and Guelph ("Cities") are considered related parties to the Corporation as they are the ultimate municipal shareholders of Alectra Inc. Revenue with the Cities include electricity distribution; street lighting; road projects; water; and sewage billing. Expenses paid include: municipal taxes; facilities rental and interest.

Arlen Energy Storage 1 LP and Vaughan 1E Energy Storage LP are related parties to the Corporation as they are joint ventures of Alectra Energy Solutions Inc., which is under common ownership with the Corporation. Revenue with these related parties include services performed for the infrastructure upgrade.

These transactions are summarized in the table below:

	2025				
	Revenue/ Deferred revenue	Expenses	Capital	Due from related parties[1]	Due to related parties[2]
Alectra Energy Solutions Inc.	3	4	1	1	1
Alectra Inc.	—	113	—	—	15
City of Barrie	8	—	—	1	—
City of Guelph	12	—	—	2	7
City of Hamilton	38	2	—	4	27
City of Markham	10	1	—	3	13
City of Mississauga	19	1	—	3	—
City of St. Catharines	4	—	—	1	—
City of Vaughan	11	1	—	2	16
Arlen Energy Storage 1 LP	1	—	—	—	—
Vaughan 1E Energy Storage 1 LP	1	—	—	—	—
	107	122	1	17	79

[1] Refer to Note 16.

[2] Refer to Note 9.

(In millions of Canadian dollars)

10. Related Party Balances and Transactions (continued)

(a) Balances and transactions with related parties (continued)

	2024				
	Revenue/ Deferred revenue	Expenses	Capital	Due from related parties[1]	Due to related parties[2]
Alectra Energy Solutions Inc.	2	4	5	1	1
Alectra Inc.	—	116	—	2	15
City of Barrie	8	—	—	2	—
City of Guelph	11	—	—	—	7
City of Hamilton	37	1	—	5	26
City of Markham	9	1	—	2	11
City of Mississauga	17	1	—	2	—
City of St. Catharines	4	—	—	1	—
City of Vaughan	10	1	—	4	14
	98	124	5	19	74

[1] Refer to Note 16.

[2] Refer to Note 9.

(b) Key management personnel compensation

Key management personnel include individuals who have direct or indirect responsibility for planning, directing, and controlling the activities of the Corporation. Annual compensation of key management personnel is included in operating expenses in the Consolidated Statement of Income and Comprehensive Income.

	2025	2024
Salaries and current employment benefits	16	16
Employee future benefits	2	1
	18	17

(c) Other related party transactions

The corporation has lease agreements with the City of Hamilton, City of Barrie and City of Markham that are included in RoU assets. Refer to Note 6 and 15.

The Corporation has unsecured intercompany loans with Alectra Inc. as described in Note 12.

The Corporation paid dividends to the shareholders during the year. Refer to Note 14.

(In millions of Canadian dollars)

11. Other Liabilities

	2025	2024
Current		
Advance payments	87	91
Income tax payable	2	5
Other	—	2
	89	98
Non-current		
Expansion deposits	32	30
Decommissioning provision	4	4
	36	34

Advance payments represent amounts received from customers and developers for services that will be performed in the future and are recognized in revenue when the performance obligations are satisfied.

Expansion deposits represent security deposits received from customers, which are expected to be returned to the customer upon project completion.

The decommissioning provision reflects the Corporation's obligation to restore leased rooftops upon lease expiry or termination. Based on contractual terms, the related restoration activities are expected to occur between 2031 to 2036.

12. Loans and Borrowings

	2025	2024
Non-current		
2.883% Promissory note due 2027[1]	602	598
5.327% Promissory note due 2030[1]	65	65
1.815% Promissory note due 2031[1]	199	199
3.441% Promissory note due 2032[2]	29	34
4.718% Promissory note due 2034[1]	199	199
4.391% Promissory note due 2034[1]	298	298
5.340% Promissory note due 2041[1]	209	209
4.010% Promissory note due 2042[1]	199	199
4.199% Promissory note due 2045[1]	30	30
3.497% Promissory note due 2049[1]	199	199
5.272% Promissory note due 2052[1]	248	248
	2,277	2,278
Current		
Intercompany variable rate grid note[3]	305	370
3.441% Promissory note due 2032 (principal payments)[2]	5	5
	310	375

All loans and borrowings are payable to Alectra Inc. All interest rates are per annum.
[1] payable at maturity date with interest paid semi-annually.
[2] interest paid monthly.
[3] principal payments due within a year with interest settled at the time of borrowing.

(In millions of Canadian dollars)

12. Loans and Borrowings (continued)

Promissory notes are presented net of transaction costs. Interest on promissory notes was $88 (2024 - $81). Refer to Note 21.

The Corporation has access to short-term liquidity through an intercompany loan agreement with its parent, Alectra Inc., which is funded under Alectra Inc.'s $1,100 (2024 – $1,100) credit facilities. The Corporation may borrow from Alectra Inc. on a revolving basis to support general corporate purposes, capital investments, working capital needs, and prudential obligations to the IESO. As at December 31, 2025, the Corporation had borrowed $305 (2024 - $370). Interest expense on the intercompany loan was $13 (2024 - $23). For the year ended December 31, 2025, the average annual outstanding variable-rate grid notes were $449 (2024 - $497) with a weighted average interest rate of 2.85% (2024 - 4.68%).

The table below summarizes principal repayments on loans and borrowings due in the next five years and thereafter as at December 31, 2025.

2026	310
2027	610
2028	5
2029	5
2030	71
Thereafter	1,599
	2,600

13. Employee Future Benefits

(a) Multi-employer defined benefit pension plan

The Corporation provides a pension plan for its employees through OMERS. The plan is a multi-employer, contributory defined benefit pension plan with equal contributions by the Corporation and its employees. During the year ended December 31, 2025, the Corporation made employer contributions of $21 (2024 - $19) to OMERS. These contributions have been recognized as an expense net of the amount capitalized in assets. The expected payment for 2026 is $23 and represents 94% of the group plan contributions. As at December 31, 2024, and subject to the estimates, assumptions and valuations of OMERS, the plan obligations are 98% (2023 - 97%) funded by its assets. 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.

(b) Non-pension defined benefit plans

The Corporation provides certain unfunded health, dental and life insurance benefits on behalf of its retired employees, based on the availability of such through group defined benefit plans administered by its parent, Alectra Inc. A policy is in place to allocate the net defined benefit cost among participating entities based on obligations attributable to their respective plan participants. There are four defined benefit plans. Independent actuarial valuations of the plans were performed as at December 31, 2025. The group defined benefit plans collectively provide benefits to eligible retirees of the Corporation.

(In millions of Canadian dollars)

13. Employee Future Benefits (continued)

(b) Non-pension defined benefit plans (continued)

Information on the Corporation's unfunded defined benefit plans, including changes in the present value of the aggregate obligation and the accrued benefit liability, is as follows:

	2025	2024
Defined benefit obligation at January 1	74	75
Benefit cost recognized in net income		
Current service costs	1	1
Interest expense	4	2
Benefit cost recognized in net income	5	3
Amounts recognized in other comprehensive income		
Remeasurement of defined benefit obligation	(5)	(1)
Actuarial losses arising from changes in experience adjustments	1	—
Amounts recognized in other comprehensive income	(4)	(1)
Payments from the plans	(3)	(3)
Defined benefit obligation at December 31	72	74

The main actuarial assumptions underlying the valuation are as follows:

	2025	2024
Discount rate	4.9 %	4.7 %
Medical benefits costs escalation	5.3 %	5.1 %
Dental benefits costs escalation	5.6 %	5.4 %

(c) Sensitivity analysis

The approximate effect on the defined benefit obligation if the main actuarial assumptions underlying the valuation increased or decreased by 1% is as follows:

		2025	2024
Discount rate	1% increase	(8)	(9)
	1% decrease	10	11
Medical and dental benefits costs escalation	1% increase	7	9
	1% decrease	(6)	(7)

(In millions of Canadian dollars)

14. Share Capital

The Corporation's authorized share capital is comprised of an unlimited number of voting common shares and 99,999 Class S non-voting shares, all of which are without nominal or par value as follows:

	2025		2024	
	Number of shares	Amount	Number of shares	Amount
Issued and outstanding				
Common shares	114,149	682	114,149	682
Issued and outstanding				
Class S shares	99,999	22	99,999	25
	214,148	704	214,148	707

During the year, the Board of Directors approved a return of capital to the Class S shareholders in the amount of $3 (2024 - $2) in accordance with the Alectra Dividend Policy incorporated as Schedule C to its Unanimous Shareholder's Agreement.

Dividends on the common shares and Class S shares of the Corporation may be approved by the Board of Directors through a resolution.

During the year, the Corporation declared and paid dividends as follows:

- Common share dividends aggregating $67 or $592.21 per share (2024 - $76 or $661.29 per share); and
- Class S share dividends aggregating $1 or $5.76 per share (2024 - $1 or $14.72 per share).

The Class S share dividends, other than return of capital, are subject to Part VI.1 tax under the *Income Tax Act (Canada)* at a rate of 25% based on the amount of dividend paid. The Corporation is also eligible for a corresponding deduction equal to a specified multiple of the dividend. The deduction does not fully offset the Part VI.1 tax, resulting in a net effective tax rate of 1.8% on the Class S share dividends to the former PowerStream Shareholders.

Subsequent to the year end, on March 5, 2026, the Corporation declared a dividend in the amount of $33 on its common shares payable to its shareholders. The Corporation has also declared a return of capital in the amount of $1 on Class S shares payable to its shareholders.

15. Lease Obligations

The Corporation leases assets including properties for its various offices and operation centre, building rooftops for installing and operating solar panels projects, vehicles, and equipment. Property leases which include both land and building elements, of which the land portion does not qualify as a lease is not included in the lease liability.

The Corporation has various property leases with different lease terms with extension options and bargain purchase options at the end of lease term. The Corporation has assessed that it is not likely to exercise the purchase options and extension options and therefore, such options are not included in the measurement of lease obligation.

(In millions of Canadian dollars)

15. Lease Obligations (continued)

The contractual undiscounted cash flows for lease obligations are as follows:

	2025	2024
Less than one year	3	3
Between one and five years	11	10
More than five years	10	13
Total undiscounted lease obligations	24	26

The Corporation expensed the land portion of the operations centre lease.

Amounts recognized in the Consolidated Statement of Income and Comprehensive Income are as follows:

	2025	2024
Interest on lease obligations	1	1
Variable lease payments and non-lease components not included in the measurement of lease obligations	1	1
	2	2

Amounts recognized in the Consolidated Statement of Cash Flows are as follows:

	2025	2024
Payments for the principal portion included in financing activities	2	1
Payments for the interest portion included in financing activities	1	1
Variable lease payments included in operating activities	1	1
Total cash outflow for leases	4	3

(In millions of Canadian dollars)

16. Financial Instruments and Risk Management

(a) Fair value of financial instruments

The carrying amount of cash, trade and other receivables, customer deposits, trade and other payables and current portion of loans and borrowings approximates fair value because of the short maturity of these instruments.

		2025		2024	
	Maturity Date	Carrying Value[1]	Fair Value[2]	Carrying Value[1]	Fair Value[2]
Loans and borrowings					
Promissory notes issued in 2017	2027	605	602	605	593
Promissory notes issued in 2010	2030	65	70	65	70
Promissory notes issued in 2021	2031	200	184	200	179
Promissory notes issued in 2017	2032	30	30	34	34
Promissory notes issued in 2024	2034	200	209	200	209
Promissory notes issued in 2024	2034	300	305	300	304
Promissory notes issued in 2011	2041	210	225	210	229
Promissory notes issued in 2012	2042	200	182	200	186
Promissory notes issued in 2015	2045	30	27	30	28
Promissory notes issued in 2019	2049	200	163	200	169
Promissory notes issued in 2022	2052	250	265	250	277
Total loans and borrowings - long-term portion		2,290	2,262	2,294	2,278
Unamortized transaction costs		(13)	—	(16)	—
		2,277	2,262	2,278	2,278

[1] The carrying value of long-term debt represents the par value of the promissory notes.

[2] The fair value of long-term debt is based on unadjusted year-end market prices for the same or similar debt of the same remaining maturities. The fair value measurement of long-term debt is categorized as Level 2.

(b) Financial risks

The risks associated with the Corporation's financial instruments and policies for managing these risks are described below:

(i) Credit risk

The Corporation’s primary exposure to credit risk associated with its trade and other receivables relates to customers not meeting their payment obligations for electricity consumed and billed.

The carrying amount of trade and other receivables is reduced through an allowance for ECL, determined using management’s judgment. ECL amounts recognized during the year are recorded in the Consolidated Statement of Income and Comprehensive Income, and any recoveries of amounts previously written down are credited to the same statement.

(In millions of Canadian dollars)

16. Financial Instruments and Risk Management (continued)

(b) Financial risks (continued)

(i) Credit risk (continued)

In assessing the ECL allowance, the Corporation considers current and forecasted economic and credit conditions, together with recent trends in customer collection experience. During the years ended December 31, 2025, and 2024 management revised the estimates and judgments applied in determining the ECL allowance due to heightened estimation uncertainty. This included segmenting the customer base into commercial and residential categories and applying provision rates that reflect recent and evolving collection patterns, as well as current and forward-looking macroeconomic and other relevant conditions. Customers assessed to be at higher risk of default were further identified and higher provision rates were applied to their aged receivable balance.

As at December 31, 2025, and 2024, there was no significant concentration of credit risk with respect to any financial assets.

Trade and other receivables and respective aging are as follows:

	Note	2025	2024
Trade receivable		345	355
Unbilled revenue		331	301
Due from related parties	10	17	19
Other		9	10
		702	685
ECL		(26)	(26)
Total trade and other receivables, net		676	659
Less than 30 days		646	633
30 - 60 days		23	17
61 - 90 days		9	11
Greater than 90 days		24	24
		702	685
ECL		(26)	(26)
Total trade and other receivables, net		676	659

	ECL
Balance, January 1, 2024	(30)
Additional allowances	(8)
Write-offs net of recoveries	12
Balance, December 31, 2024	(26)
Additional allowances	(10)
Write-offs net of recoveries	10
Balance, December 31, 2025	(26)

16. Financial Instruments and Risk Management (continued)

(b) Financial risks (continued)

(i) Credit risk (continued)

The measurement of ECL is sensitive to the inputs applied in the Corporation's internal credit risk models, including forward-looking macroeconomic variables and other judgment-based assumptions. A 1% increase or decrease in these inputs and assumptions would not result in a significant change to the ECL estimate.

(ii) Interest rate risk

The Corporation is subject to interest rate risk arising from fluctuations in discount rates used in valuing post-employment benefit obligations and from exposure to short-term interest rate movements on its intercompany variable-rate grid note, customer deposits liabilities, and cash balances. Refer to Note 13 and 12. Other obligations largely bear fixed rates or are non-interest bearing, and the Corporation's remaining financial assets are predominantly short-term and non-interest bearing.

Interest rate risk is managed through ongoing monitoring of the Corporation's portfolio of fixed and variable rate instruments to maintain an appropriate balance.

A 1% increase in short-term interest rates, assuming all other variables remain constant, is estimated to increase annual finance costs by approximately $4 (2024 - $4).

(In millions of Canadian dollars)

16. Financial Instruments and Risk Management (continued)

(b) Financial risks (continued)

(iii) Liquidity risk

Liquidity risk is the risk that the Corporation may be unable to meet its financial obligations as they become due. The Corporation monitors this risk by preparing undiscounted cash flow forecasts to assess its ability to meet upcoming commitments. The contractual maturity profile of the Corporation's financial liabilities, presented on an undiscounted basis, is as follows:

2025					
	Note	Due within 1 year	Due between 1 and 5 years	Due past 5 years	Total
Trade and other payables	9	500	—	—	500
Customer deposits liability		59	—	—	59
Other liabilities	11	87	32	—	119
Intercompany variable rate notes payable to Alectra Inc.	12	305	—	—	305
2.883% Promissory note due 2027[1]		15	613	—	628
5.327% Promissory note due 2030[1]		3	79	—	82
1.815% Promissory note due 2031[1]		4	14	202	220
3.441% Promissory note due 2032[1]		6	24	8	38
4.718% Promissory note due 2034[1]		9	37	232	278
4.391% Promissory note due 2034[1]		13	52	352	417
5.340% Promissory note due 2041[1]		11	44	327	382
4.010% Promissory note due 2042[1]		8	32	295	335
4.199% Promissory note due 2045[1]		1	5	49	55
3.497% Promissory note due 2049[1]		7	28	328	363
5.272% Promissory note due 2052[1]		13	52	537	602
Lease obligations[1]	15	3	11	10	24
		1,044	1,023	2,340	4,407

[1] The balances for promissory notes and lease obligations include both principal and interest.

(In millions of Canadian dollars)

16. Financial Instruments and Risk Management (continued)

(b) Financial risks (continued)

(iii) Liquidity risk (continued)

2024					
	Note	Due within 1 year	Due between 1 and 5 years	Due past 5 years	Total
Trade and other payables	9	458	—	—	458
Customer deposits liability		58	—	—	58
Other liabilities	11	91	30	—	121
Intercompany variable rate notes payable to Alectra Inc.	12	370	—	—	370
2.883% Promissory note due 2027[1]		15	628	—	643
5.327% Promissory note due 2030[1]		3	14	68	85
1.815% Promissory note due 2031[1]		4	14	205	223
3.441% Promissory note due 2032[1]		6	24	14	44
4.718% Promissory note due 2034[1]		9	37	242	288
4.391% Promissory note due 2034[1]		13	52	365	430
5.340% Promissory note due 2041[1]		11	44	338	393
4.010% Promissory note due 2042[1]		8	32	303	343
4.199% Promissory note due 2045[1]		1	5	50	56
3.497% Promissory note due 2049[1]		7	28	335	370
5.272% Promissory note due 2052[1]		13	52	550	615
Lease obligations[1]	15	3	10	13	26
		1,070	970	2,483	4,523

[1] The balances for promissory notes and lease obligations include both principal and interest.

The Corporation actively manages liquidity risk to ensure it has access to sufficient funds to meet its operational and investment requirements. Its objective is to maintain adequate liquidity to satisfy obligations as they come due while minimizing exposure to interest rate risk and financing costs. The Corporation monitors cash balances on a regular basis to ensure that sufficient liquidity is available to meet financial commitments.

(In millions of Canadian dollars)

17. Capital Structure

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

- ensure ongoing cost-effective access to financial capital and to provide adequate investment in support of its regulated electricity distribution and other businesses;
- comply with covenants within its financial instruments;
- prudently manage its capital structure, as it relates to maintaining a high level of creditworthiness;
- recover financing charges permitted by the OEB on its regulated electricity distribution business; and
- deliver reasonable returns on the investments of its shareholders.

The Corporation's definition of capital includes current and long-term portion of the loans and borrowings, and shareholders' equity. The following table represents the Corporation's total capital:

	Note	2025	2024
Current portion of loans and borrowings	12	310	375
Long-term portion of loans and borrowings	12	2,277	2,278
Shareholders' equity		1,968	1,825
		4,555	4,478

The OEB regulates the amount of interest on debt and the MARE that may be recovered by the Corporation through its electricity distribution rates for its regulated electricity distribution business. These recoveries are permitted based on a deemed capital structure of 60% debt to rate base and 40% equity to rate base. The Corporation's actual capital structure may differ from the OEB-approved deemed structure.

18. Revenue

	2025	2024
Electricity sales	3,622	3,306
Distribution revenue	733	797
Amortization and derecognition of capital contributions	25	23
Regulatory service charges	14	13
Solar generation	14	15
Water and wastewater billing and customer charges	13	12
Pole and other rental income	7	6
CDM revenue	—	1
Other	9	8
	4,437	4,181

(In millions of Canadian dollars)

18. Revenue (continued)

Energy sales and distribution revenue by customer class are as follows:

	2025	2024
Residential service[1]	1,557	1,541
Commercial[2]	2,522	2,312
Large users[3]	276	250
	4,355	4,103

[1] "Residential Service" means a service that is for domestic or household purposes, including single family or individually metered multi-family units and seasonal occupancy.

[2] "Commercial" means a service supplied to premises other than those receiving "Residential Service" and "Large Users" and typically includes small businesses and bulk-metered multi-unit residential establishments. This service is provided to customers with a monthly peak demand of less than 5,000 kW averaged over a 12-month period.

[3] "Large Users" means a service provided to a customer with a monthly peak demand of 5,000 kW or greater averaged over a 12-month period.

19. Operating Expenses

	Note	2025	2024
Labour		167	159
Contract and consulting		61	56
General and administrative		27	25
Information and technology		20	19
Repairs and maintenance		17	16
Business taxes and fees		13	12
Legal, audit and insurance		8	9
Provision for ECL	16	8	7
Facility expenses		4	4
Other		7	7
		332	314

(In millions of Canadian dollars)

20. Deferred Revenue

	Note	2025	2024
Deferred revenue at January 1		834	724
Capital contributions received		131	120
Non-cash asset contributions	6	34	13
Amortization and derecognition	18	(25)	(23)
Deferred revenue at December 31		974	834
Less current portion of deferred revenue		28	26
Non-current portion of deferred revenue		946	808

Effective January 1, 2025, deferred revenue amortization periods were revised prospectively to reflect changes in the estimated useful lives of the related Property, Plant and Equipment. Refer to Note 6. The effect of the change on the actual and expected amortization of deferred revenue is as follows:

	2025	2026	2027	2028	2029	After 2029
(Decrease) increase in amortization of deferred revenue	(2)	(2)	(2)	(2)	(2)	10

Reconciliation between the amounts presented on the Consolidated Statement of Cash Flows and total additions to customer contributions is as follows:

	2025	2024
Capital contributions, cash basis	148	109
Adjustment for accruals	(17)	11
Total capital contributions received	131	120

21. Net Finance Costs

	Notes	2025	2024
Finance costs			
Interest on long-term loans and borrowings	12	88	81
Interest on short-term debt	12	13	23
Other interest		5	8
Capitalized borrowings costs	6, 7	(3)	(3)
Total finance costs		103	109
Interest income		(5)	(7)
		98	102

(In millions of Canadian dollars)

22. Income Taxes

(a) Income tax expense

PILs recognized in the Consolidated Statement of Income and Comprehensive Income comprise the following:

	2025	2024
Current tax expense	18	18
Deferred tax expense	58	36
	76	54

Income tax paid and refunded during the year was $21 (2024 - $11) and $1 (2024 - $1), respectively.

(b) Reconciliation of the effective tax rate

PILs income tax expense differs from the amount that would have been recorded using the combined Canadian federal and provincial statutory income tax rates. The reconciliation between the statutory and effective tax rates is as follows:

	2025	2024
Income before income taxes	287	202
Statutory Canadian federal and provincial income tax rate	26.5%	26.5%
Expected tax provision on income at statutory rate	76	54
Total income tax expense	76	54
Effective income tax rate	26.5%	26.5%

The statutory income tax rate for the current year comprises a combined 15% (2024 - 15%) federal corporate tax rate and 11.5% (2024 - 11.5%) Ontario corporate tax rate.

(c) Deferred tax balances

Net deferred tax liabilities are as follows:

	January 1, 2025	Recognized in net income	Recognized in OCI	December 31, 2025
Deferred tax liabilities				
Employee future benefits	(19)	—	1	(18)
Property, plant and equipment, RoU and intangible assets	216	28	—	244
Tax credit carryovers	(4)	(1)	—	(5)
Non-deductible reserves	(1)	(1)	—	(2)
Energy variances	(19)	34	—	15
Decommissioning provision	(1)	(2)	—	(3)
	172	58	1	231

(In millions of Canadian dollars)

22. Income Taxes (continued)

(c) Deferred tax balances (continued)

	January 1, 2024	Recognized in net income	Recognized in OCI	December 31, 2024
Deferred tax liabilities				
Employee future benefits	(19)	—	—	(19)
Property, plant and equipment, RoU and intangible assets	194	22	—	216
Tax credit carryovers	(6)	2	—	(4)
Non-deductible reserves	(1)	—	—	(1)
Energy variances	(32)	13	—	(19)
Decommissioning provision	—	(1)	—	(1)
	136	36	—	172

23. Net Change in Operating Working Capital

	2025	2024
Trade and other receivables	(35)	(48)
Other assets	3	(11)
Trade and other payables	36	(23)
Customer deposits liability	1	—
Other liabilities	(7)	(13)
	(2)	(95)

(In millions of Canadian dollars)

24. Financing Activities Reconciliation

Summary of changes in assets and liabilities arising from financing activities:

	Note	January 1, 2025	Cash inflow	Cash outflow	Non-cash changes	December 31, 2025
Loans and borrowings	12	2,653	11,558	(11,627)	3	2,587
Lease obligations	15	20	—	(2)	—	18
Interest receivable[1]		(1)	6	—	(5)	—
Interest payable[2]		20	—	(103)	103	20
Share capital	14	707	—	(3)	—	704
Dividend payable	14	—	—	(68)	68	—
		3,399	11,564	(11,803)	169	3,329

[1] Included in due from related parties.

[2] Included in due to related parties and other trade payables.

	Note	January 1, 2024	Cash inflow	Cash outflow	Non-cash changes	December 31, 2024
Loans and borrowings	12	2,457	12,765	(12,570)	1	2,653
Lease obligations	15	21	—	(1)	—	20
Interest receivable[1]		—	6	—	(7)	(1)
Interest payable[2]		19	—	(108)	109	20
Share capital	14	719	—	(2)	(10)	707
Dividend payable	14	—	—	(77)	77	—
		3,216	12,771	(12,758)	170	3,399

[1] Included in due from related parties.

[2] Included in due to related parties and other trade payables.

25. Commitments, Contingencies, and Guarantees

(a) Commitments

(i) Security with IESO

In accordance with the *Electricity Act, 1998 (Ontario)* and the IESO Market Rules, the Corporation is required to provide security to the IESO to mitigate the risk of default on its market obligations. If the Corporation fails to make a required payment following a default notice from the IESO, the IESO may draw on this security. To satisfy this requirement, the Corporation has posted a letter of credit in the amount of $33 (2024 - $33).

(ii) Unrecognized contractual commitments

As at December 31, 2025, the Corporation's commitments for capital expenditures contracted for but not recognized as liabilities, were $271 (2024 - $224). Included within the commitments for capital expenditures, are amounts for property, plant and equipment, and intangible assets. The Corporation's commitments for operating expenditures were $55 (2024 - $43).

(In millions of Canadian dollars)

25. Commitments, Contingencies, and Guarantees (continued)

(a) Commitments (continued)

(ii) Unrecognized contractual commitments (continued)

Aggregated minimum payments under there arrangements over the next five years and thereafter are as follows:

2026	295
2027	12
2028	5
2029	1
2030	13

(b) Contingencies

(i) Legal and other claims

The Corporation is subject to legal actions and claims in the normal course of business from customers, former employees, and other parties. On an ongoing basis, the Corporation assesses the likelihood of any adverse judgments or outcomes as well as potential ranges of probable costs and losses. A determination of the provision required, if any, for these contingencies is made after an analysis of each individual claim. Such provisions are subject to change based on ongoing assessments or settlements of individual claims, including potential mitigation under the Corporation's insurance policies or otherwise. As at December 31, 2025, and 2024, in the opinion of management, the outcome of such matters will not have a material adverse effect on the Corporation’s Consolidated results.

(ii) Insurance

The Corporation is a member of a reciprocal insurance exchange. The reciprocal insurance exchange is a pooling of electricity industry liability insurance risks of many of the sector participants in Ontario. All members of the pool are subject to assessment for losses experienced by the pool, for the years in which they were members, on a pro-rata basis based on the total of their respective service revenues. It is anticipated that should such an assessment occur it would be funded over a period of up to five years. As at December 31, 2025, and 2024, no assessments have been made.

(c) Guarantees

In the normal course of operations, the Corporation enters into agreements that meet the definition of a guarantee as follows:

(i) The Corporation has provided indemnities under lease agreements for the use of certain operating facilities. Under the terms of these agreements, the Corporation agrees to indemnify the counterparties for various matters including, but not limited to, all liabilities, loss, suits, and damages arising during, on or after the term of the agreement. The maximum amount of any potential future payment cannot be reasonably estimated.

25. Commitments, Contingencies, and Guarantees (continued)

(c) Guarantees (continued)

(ii) The Corporation has agreed to indemnify the directors and/or officers of the Corporation for various matters including, but not limited to, all costs to settle suits or actions due to association with the Corporation, subject to certain restrictions. The Corporation has purchased directors' and officers' liability insurance to mitigate the cost of any potential future suits or actions. The indemnified period is not explicitly defined, but it is limited to the period over which the indemnified party served as a director or officer of the Corporation. The maximum amount of any potential future payment cannot be reasonably estimated.

(iii) In the normal course of business, the Corporation has entered into agreements that include indemnities in favour of counterparties, such as purchase and sale agreements, confidentiality agreements, engagement letters with advisor's and consultants, outsourcing agreements, leasing contracts, information technology agreements, and service agreements. These indemnification agreements may require the Corporation to compensate counterparties for certain losses incurred by the counterparties as a result of breaches of agreements such as breaches of representation or regulations or as a result of litigation claims or statutory sanctions that may be suffered by the counterparty as a consequence of the transaction. The terms of these indemnities are not explicitly defined, and the maximum amount of any potential reimbursement cannot be reasonably estimated.

The nature of these indemnification agreements prevents the Corporation from making a reasonable estimate of the maximum exposure due to the difficulties in assessing the amount of liability, which results from the unpredictability of future events.

(In millions of Canadian dollars)

26. Divisional and Regulatory Information

The Corporation consists primarily of two operating divisions: regulated operations and competitive operations. Competitive operations are comprised of RFSP, Solar Sunbelt, and the Southgate Solar Photovoltaic Facility.

The designation of activities to the two operating divisions is based on a combination of regulatory status and the nature of the products and services provided. The accounting policies followed by the divisions are consistent with those described in the summary of material accounting policies.

Financial information that adjusts IFRS results to show the effect of rate regulation is used by the Corporation's Board of Directors, the shareholders, OEB, as well as management.

	2025			
	Regulated	Adjustment for regulatory activities	Competitive activities	Total
Revenue				
Distribution revenue	696	37	—	733
Electricity sales	3,523	99	—	3,622
Other revenue	16	52	14	82
	4,235	**188**	**14**	**4,437**
Expenses				
Cost of power	3,523	—	—	3,523
Operating expenses	315	15	2	332
Depreciation and amortization	157	24	8	189
	3,995	**39**	**10**	**4,044**
Income from operating activities	**240**	**149**	**4**	**393**
Net finance costs	(96)	—	(2)	(98)
Net loss on derecognition of property, plant and equipment and intangible assets	(6)	(2)	—	(8)
Income before income taxes	**138**	**147**	**2**	**287**
Income tax expense	(12)	(64)	—	(76)
Net income	**126**	**83**	**2**	**211**
Other comprehensive income				
Remeasurement of defined benefit obligation	1	3	—	4
Tax impact on remeasurement of defined benefit obligation	—	(1)	—	(1)
	1	**2**	**—**	**3**
Total comprehensive income	**127**	**85**	**2**	**214**

(In millions of Canadian dollars)

26. Divisional and Regulatory Information (continued)

2024	Regulated	Adjustment for regulatory activities	Competitive activities	Total
Revenue				
Distribution revenue	671	126	—	797
Electricity sales	3,356	(50)	—	3,306
Other revenue	34	29	15	78
	4,061	**105**	**15**	**4,181**
Expenses				
Cost of power	3,356	—	—	3,356
Operating expenses	295	16	3	314
Depreciation and amortization	164	22	9	195
	3,815	**38**	**12**	**3,865**
Income from operating activities	**246**	**67**	**3**	**316**
Net finance costs	(95)	(4)	(3)	(102)
Net loss on derecognition of property, plant and equipment	(10)	(2)	—	(12)
Income before income taxes	**141**	**61**	**—**	**202**
Income tax expense	(21)	(33)	—	(54)
Net income	**120**	**28**	**—**	**148**
Other comprehensive income				
Remeasurement of defined benefit obligation	1	—	—	1
	1	**—**	**—**	**1**
Total comprehensive income	**121**	**28**	**—**	**149**

(In millions of Canadian dollars)

26. Divisional and Regulatory Information (continued)

2025	Regulated	Adjustment for regulatory activities	Competitive activities	Total
Assets				
Current assets				
Cash	5	—	8	13
Trade and other receivables	675	—	1	676
Other assets	83	—	—	83
Total current assets	**763**	**—**	**9**	**772**
Non-current assets				
Property, plant and equipment and right of use assets	3,777	983	60	4,820
Goodwill and other intangible assets	940	7	—	947
Regulatory assets	388	(388)	—	—
Other assets	8	—	(4)	4
Total non-current assets	**5,113**	**602**	**56**	**5,771**
Total assets	**5,876**	**602**	**65**	**6,543**
Liabilities and Shareholders' Equity				
Current liabilities				
Trade and other payables	510	(1)	—	509
Customer deposits liability	59	—	—	59
Deferred revenue	—	28	—	28
Lease obligations	1	—	1	2
Loans and borrowings	305	—	5	310
Other liabilities	89	—	—	89
Total current liabilities	**964**	**27**	**6**	**997**
Non-current liabilities				
Deferred revenue	—	946	—	946
Employee future benefits	72	—	—	72
Lease obligations	9	—	7	16
Loans and borrowings	2,247	—	30	2,277
Regulatory liabilities	175	(175)	—	—
Deferred tax liabilities	260	(41)	12	231
Other liabilities	53	(21)	4	36
Total non-current liabilities	**2,816**	**709**	**53**	**3,578**
Total liabilities	**3,780**	**736**	**59**	**4,575**
Shareholders' equity				
Share capital	683	—	21	704
Contributed surplus	839	(13)	—	826
Accumulated other comprehensive income	5	6	1	12
Retained earnings	569	(127)	(16)	426
Total shareholders' equity	**2,096**	**(134)**	**6**	**1,968**
Total liabilities and shareholders' equity	**5,876**	**602**	**65**	**6,543**

(In millions of Canadian dollars)

26. Divisional and Regulatory Information (continued)

2024				
	Regulated	Adjustment for regulatory activities	Competitive activities	Total
Assets				
Current assets				
Cash	37	—	8	45
Trade and other receivables	659	—	—	659
Other assets	86	—	—	86
Total current assets	**782**	**—**	**8**	**790**
Non-current assets				
Property, plant and equipment and right of use assets	3,577	845	68	4,490
Goodwill and other intangible assets	936	8	—	944
Regulatory assets	437	(437)	—	—
Other assets	8	—	(4)	4
Total non-current assets	**4,958**	**416**	**64**	**5,438**
Total assets	**5,740**	**416**	**72**	**6,228**
Liabilities and Shareholders' Equity				
Current liabilities				
Trade and other payables	460	—	—	460
Customer deposits liability	58	—	—	58
Loans and borrowings	370	—	5	375
Lease obligations	1	—	1	2
Deferred revenue	—	26	—	26
Other liabilities	98	—	—	98
Total current liabilities	**987**	**26**	**6**	**1,019**
Non-current liabilities				
Deferred revenue	—	808	—	808
Employee future benefits	74	—	—	74
Lease obligations	10	—	8	18
Loans and borrowings	2,245	—	33	2,278
Regulatory liabilities	130	(130)	—	—
Deferred tax liabilities	230	(71)	13	172
Other liabilities	30	—	4	34
Total non-current liabilities	**2,719**	**607**	**58**	**3,384**
Total liabilities	**3,706**	**633**	**64**	**4,403**
Shareholders' equity				
Share capital	682	—	25	707
Contributed surplus	839	(13)	—	826
Accumulated other comprehensive income	4	5	—	9
Retained earnings	509	(209)	(17)	283
Total shareholders' equity	**2,034**	**(217)**	**8**	**1,825**
Total liabilities and shareholders' equity	**5,740**	**416**	**72**	**6,228**

(In millions of Canadian dollars)

26. Divisional and Regulatory Information (continued)

The Corporation derecognizes all rate-regulated debit and credit balances that do not qualify for recognition under IFRS. The table below presents a summary of rate-regulated debit and credit balances as prescribed by the OEB irrespective of their recognition under IFRS.

	2025	2024
Regulatory Assets		
Deferred income tax asset[a]	287	252
Retail settlement variance accounts (RSVA's)[b]	21	116
OEB cost assessments deferral[c]	20	16
Large commercial interval meter recovery[d]	17	16
Collection of account lost revenue[e]	17	15
Net recovery of regulatory balances[f]	10	11
Incremental locate costs deferral[g]	8	5
Renewable generation capital and operating cost deferral[h]	4	4
LEAP EFA Funding Deferral[i]	2	1
Incremental cloud Implementation Cost[j]	2	1
	388	437
Regulatory Liabilities		
Retail settlement variance accounts (RSVA's)[b]	67	37
PILs and tax variance[k]	41	40
Capitalization policy[l]	31	25
Pole rental variance account[m]	19	16
Re-measurements of post-employment benefits[n]	10	7
Other[o]	7	5
	175	130

(a) Deferred income taxes are presented as regulatory liabilities or assets and are not expensed through the Consolidated Statement of Income and Comprehensive Income as is the case under IFRS.

(b) The most significant regulatory activities included in the regulatory adjustments are: retail settlement variances; the difference between the cost of the electricity commodity and the sales revenue at the OEB allowed rates. Specifically, these amounts include variances between the amounts charged by Hydro One and the IESO for the operation of the electricity markets and grid, as well as various wholesale market settlement charges and transmission charges as compared to the amount billed to consumers based on the OEB-approved rates. Under regulatory accounting, the Corporation would have adjusted energy sales or purchases for these variances with corresponding assets or liabilities. Under IFRS, the Corporation recognizes these differences in future periods as an increase or decrease to distribution revenue, when these differences are settled with customers.

(c) The OEB established a variance account for electricity distributors to record any material differences between OEB cost assessments currently built into rates and cost assessments that results from the application of a new cost assessment model implemented as of April 1, 2016. Under IFRS, the Corporation recognizes these costs under operating expenses in the period they were incurred.

26. Divisional and Regulatory Information (continued)

(d) The OEB approved a deferral account to record costs associated with replacing interval meters for its large commercial customers in order to meet amendments made to its Distribution System Code. Under IFRS, the Corporation capitalizes or expenses the amounts in the period they were incurred.

(e) The OEB approved a deferral account to record the lost revenues related to the administration of the Collection of Account charge. In 2020, the OEB mandated that collection of account charges are part of normal business activities and eliminated any customer charges for this activity. However, as the associated revenue was factored into the rate-setting process the established deferral account allows the Corporation to record the lost revenues for recovery through future distribution rates.

(f) The OEB approved deferral accounts to record the amounts recovered (or refunded) through rates including those recovered (or refunded) through deferral and variance accounts rate riders. Under IFRS, the Corporation recognizes amounts collected or refunded through rate riders as an increase or decrease to distribution revenue.

(g) The OEB established a generic, sector-wide variance account, effective April 1, 2023, to record the incremental cost of locates resulting from the implementation of Bill 93. The bill includes amendments to the *Ontario Underground Notification System Act, 2012* imposing a five-business day deadline for completing standard locate requests and introducing administrative penalties for failing to comply. Under IFRS, the Corporation recognizes costs of locates under operating expenses in the period they were incurred.

(h) The OEB approved four deferral accounts to record qualifying incremental capital investments, operating, maintenance and administration expenses, and funding adders related to the connection of renewable generation or the development of smart grid. Under IFRS, the Corporation capitalizes or expenses these items as incurred and recognizes revenue when funding is received.

(i) The OEB established a generic deferral account effective March 1, 2024, for electricity distributors to record prudently incurred incremental Low-income Energy Assistance Emergency Financial Assistance (LEAP EFA) contributions that exceed the funding amounts currently embedded in their rates. Under IFRS, the Corporation recognizes LEAP EFA contributions under operating expenses in the period they were incurred.

(j) The OEB established a deferral account effective December 1, 2023 to record incremental cloud computing implementation costs incurred and any related offsetting savings. Under IFRS, the Corporate recognizes cloud computing implementation costs under operating expenses in the period they were incurred.

(k) The OEB requires utilities to record the impact of any differences that result from a legislative or regulatory change to the tax rates or rules that are not incorporated in the distributor's rates. On June 21, 2019, Bill C-97, the Budget Implementation Act, 2019, No. 1, was given Royal Assent, which introduced the Accelerated Investment Incentive ("AII") program. This program provides for a first-year increase in capital cost allowance (CCA) deductions on eligible capital assets acquired after November 20, 2018. On June 23, 2022, Bill C-19, Budget Implementation Act, 2022, No. 1, was given Royal Asset. Bill C-19 implements new CCA immediate expensing rules, up to a maximum of $1.5MM, on eligible capital assets acquired after April 19, 2021, and available for use before January 1, 2024. The Corporation has recorded the revenue related to the CCA tax rule changes to be refunded through future distribution rates.

26. Divisional and Regulatory Information (continued)

(l) The OEB approved four variance accounts to record the cumulative difference between the PP&E calculated using pre-merger capitalization policies and the PP&E calculated using the Corporation's capitalization policy. Under IFRS, the Corporation recognizes these differences as an increase or decrease to distribution revenue and will recover or refund these differences through future distribution rates.

(m) The OEB approved a new pole attachment revenue variance account to record the difference between pole attachment revenue at the prior rate of $22.35 per pole, and pole attachment revenue based on the updated rate as set by the OEB. In 2025, the new pole attachment charge is set at $39.14 (2024 - $37.78) per pole based on the OEB's decision issued on September 26, 2024. Under IFRS, the Corporation recognizes the revenue based on the effective rate in the period the revenue was earned.

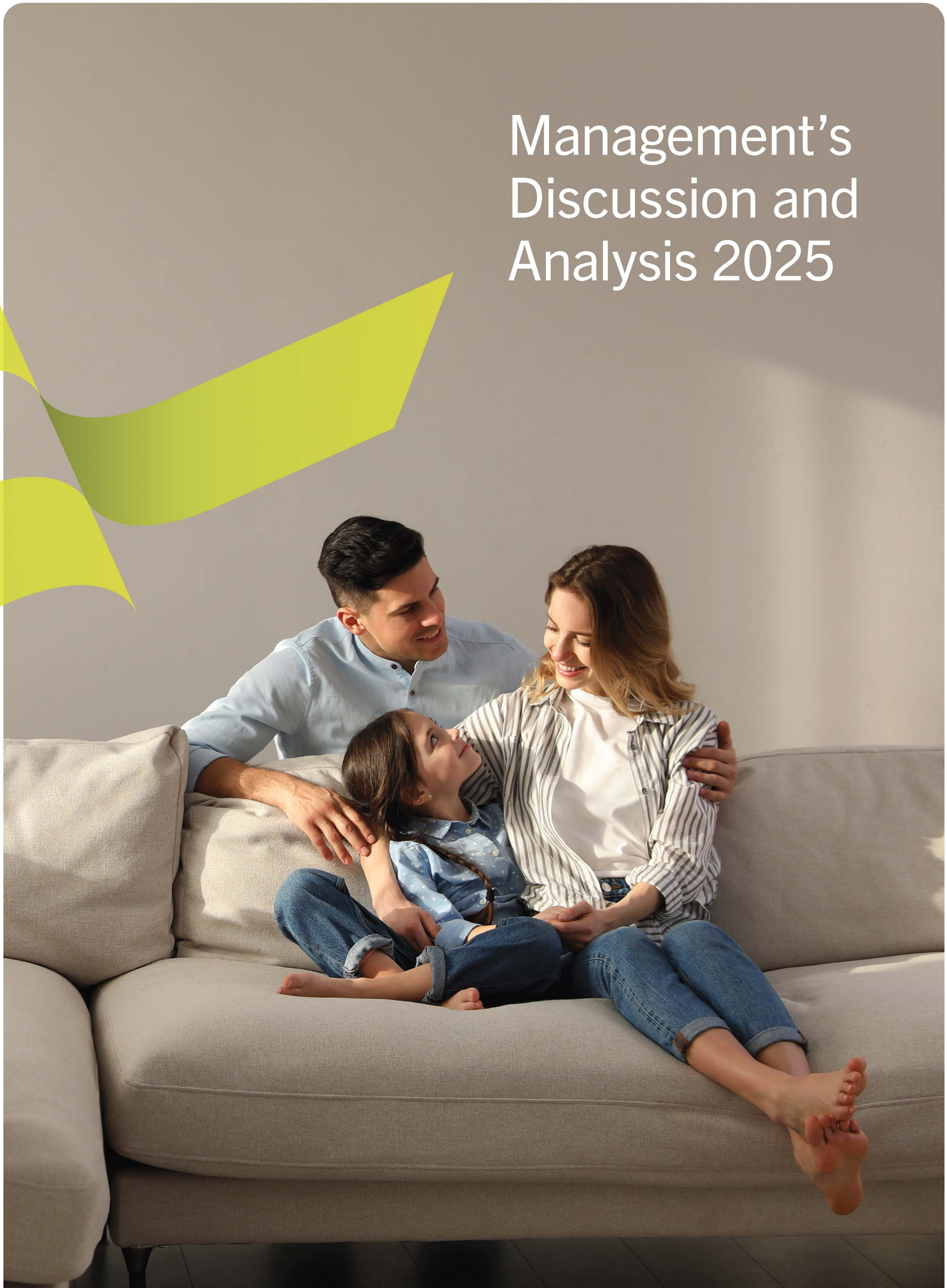
(n) The OEB approved a deferral account for PowerStream, Enersource and Guelph rate zones to record any re-measurements of the post-employment net defined liability including actuarial gains or losses. Under IFRS, the Corporation recognizes any re-measurements of the post-employment net defined liability in other comprehensive income.

(o) The OEB requires the Corporation to record eligible incremental capital investments subject to the assets being used and useful, accumulated amortization and revenues collected through rate riders related to incremental capital projects approved by the OEB. Under IFRS, the Corporation capitalizes or expenses these items as incurred and recognizes revenue in the period it was earned.

Attachment 1-14

2025 Management's Discussion and Analysis

Management's Discussion and Analysis 2025



Management's Discussion and Analysis

This Management's Discussion and Analysis ("MD&A") contains important information about our business and our performance for the year ended December 31, 2025, (the "Consolidated Financial Statements"). This MD&A should be read in conjunction with the Corporation's Consolidated Financial Statements and accompanying notes as at and for the years ended December 31, 2025 and 2024, which were prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB") and in effect at December 31, 2025. All dollar amounts are in millions of Canadian dollars, which are presented in whole numbers. All percentage changes are calculated using the rounded numbers as they appear in the tables. 2024 amounts are re-presented as a result of the discontinued operation. Refer to note 7 in the Consolidated Financial Statements.

Contents

Glossary

The following acronyms and abbreviations are used in this document.

AES	Alectra Energy Solutions Inc.
AESI	Alectra Energy Services Inc.
AFFO	Adjusted Funds from Operations
Alectra	Alectra Inc.
Alectra Utilities	Alectra Utilities Corporation
APSI	Alectra Power Services Inc.
CAM	Capacity Allocation Model
CAPEX	Capital Expenditures
CC	Customer Contributions
CP	Commercial Paper
DBRS	Dominion Bond Rating Service
DER	Distributed Energy Resource
DVA	Deferral and Variance Accounts
EBITDA	Earnings before interest, taxes, depreciation, and amortization
ECL	Expected Credit Loss
GHG	Greenhouse Gas
GLC	Gagnon Line Construction Inc.
HPSI	Holland Power Services Inc.
IASB	International Accounting Standards Board
IBEW	International Brotherhood of Electrical Workers
ICM	Incremental Capital Module
IDR	Issuer Default Rating
IESO	Independent Electricity System Operator
IFRS	International Financial Reporting Standards
IR	Incentive Rate
LDC	Local Distribution Company
LRAMVA	Lost Revenue Adjustment Mechanism Variance Account
MD&A	Management's Discussion and Analysis
MIFRS	Modified International Financial Reporting Standards
OEB	Ontario Energy Board
OEBA	Ontario Energy Board Act
OEFC	Ontario Electricity Finance Corporation
PP&E	Property, Plant and Equipment
PWU	Power Workers' Union
ROE	Return on Equity
RoU	Right of Use
RRF	Renewed Regulatory Framework for Electricity Distributors
S&P	Standard & Poor's
SAIDI	System Average Interruption Duration Index, Adjusted Excluding Loss of Supply and Major Events
SAIFI	System Average Interruption Frequency Index, Adjusted Excluding Loss of Supply and Major Events
SP	Spare Parts
VASH	Vulnerability & System Hardening
WMS	Wholesale Market Service Charge

LEGEND

	Higher	Lower
Revenue	↑	↓
Expenses	↑	↓

	Lower	Higher
Assets	↓	↑
Liabilities	↓	↑

Forward Looking Statements and Information

The oral and written public communications of Alectra Inc. ("the Corporation"), including this document, often contain forward-looking statements that are based on current expectations, estimates, forecasts and projections about the business and the industry in which the Corporation operates, and include beliefs and assumptions made by the management of the Corporation. Such statements include, but are not limited to:

- Statements about strategy, including strategic objectives;
- Statements related to economic conditions;
- Statements regarding liquidity and capital resources and operational requirements;
- Statements regarding credit facilities and other sources of corporate liquidity;
- Statements regarding ongoing and planned projects and/or initiatives including the expected results of these projects and/or initiatives and their completion dates;
- Statements regarding expected future capital and development expenditures, the timing of these expenditures and investment plans;
- Statements regarding contractual obligations and other commercial commitments;
- Statements related to the Ontario Energy Board ("OEB");
- Statements regarding future post-retirement benefit contributions, and actuarial valuations;
- Statements related to the outlook and approach of the Corporation to distribution sector rationalization;
- The estimated impact of changes in the forecasted long-term Government of Canada bond yield (used in determining the regulated rate of return) on the results of operations;
- Expectations regarding financing activities; and
- Expectations regarding the recoverability of large capital expenditures.

Words such as “expect”, “anticipate”, “intend”, “attempt”, “may”, “plan”, “will”, “believe”, “seek”, “estimate”, “goal”, “aim”, “target”, and variations of such words and similar expressions are intended to identify such forward-looking statements. These statements are not guarantees of future performance and involve assumptions, risks and uncertainties that are difficult to predict. Therefore, actual outcomes and results may differ materially from what is expressed, implied or forecasted in such forward-looking statements.

The Corporation does not intend, and disclaims any obligation, to update any forward-looking statements, except as required by law. These forward-looking statements are based on a variety of factors and assumptions including, but not limited to the following:

- Unforeseen changes in the legislative and operating framework for Ontario’s electricity market;
- Decisions from the OEB and other regulatory bodies concerning outstanding rate and other applications;
- Delays in obtaining required approvals;
- Unforeseen changes in rate orders or rate structures;
- A stable regulatory environment;
- Unexpected changes in environmental regulation; and
- Unforeseen significant events occurring outside the ordinary course of business.

These assumptions are based on information currently available to the Corporation, including information obtained from third-party sources. Actual results may significantly differ from those predicted by such forward-looking statements.

Forward Looking Statements and Information (continued)

Readers are cautioned that the above list of factors is not exhaustive. Some of these and other factors are discussed in more detail in the section “Risk Management and Risks” in this MD&A. In addition, the Corporation cautions the reader that information provided in this MD&A regarding the Corporation’s outlook on certain matters, including future expenditures, is provided in order to give context to the nature of some of the Corporation’s future plans and may not be appropriate for other purposes.

2025 Performance at a Glance

(in millions of Canadian Dollars)

Total Assets **$6,851**	Net Income **$227**
Revenue **$4,536**	Expenses **$4,170**
Dividends Paid **$79**	Loans and borrowings **$2,775**
MIFRS Net Income[1] **$144**	MIFRS EBITDA [1] **$396**

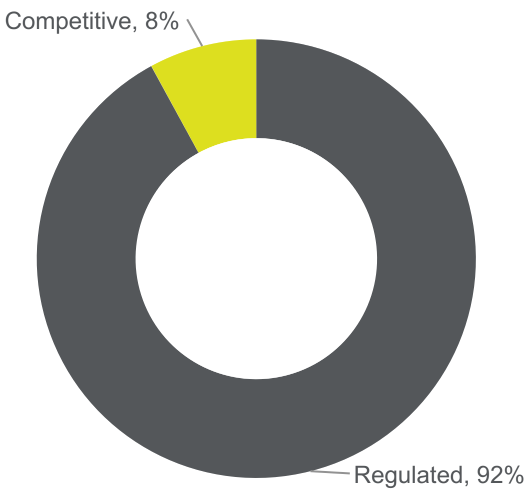
1 MIFRS Net Income for Regulatory Activities represents the net income for the year, adjusted for the effect of rate regulation. Refer to Note 29 of the Consolidated Financial Statements for details.

KEY BUSINESS STATISTICS

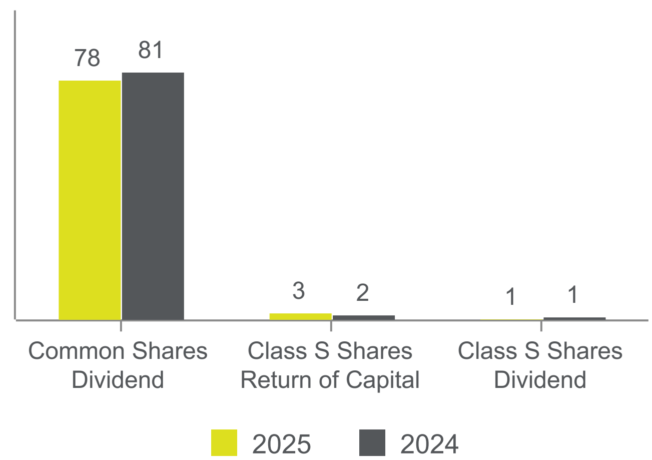
Key Metrics	2025 Performance	2024 Performance	2024 Average Urban Distributor Benchmark[2]
Distribution volume in GWh	**28,010**	**27,251**	**n/a**
SAIDI	**0.88**	**0.75**	**1.07**
SAIFI	**1.26**	**1.08**	**1.17**

2 The Average Urban Distributor is based on the average 2024 System Average Interruption Duration Index ("SAIDI") and System Average Interruption Frequency Index ("SAIFI") performance results for Urban Ontario Distributors with at least 50k customers from 2024 Open Data published by the OEB.

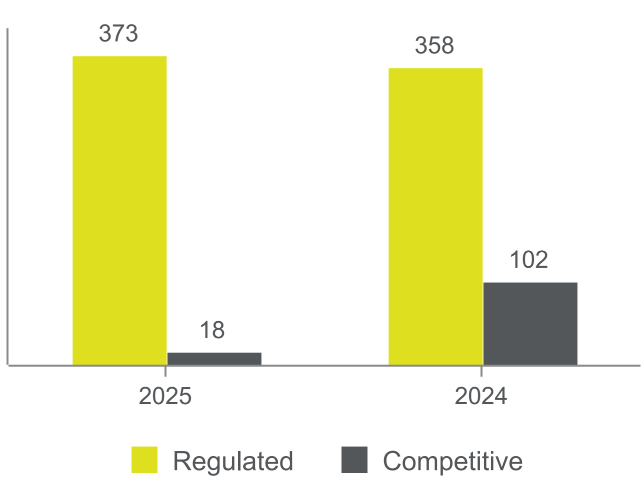
2025 Net Income Breakdown



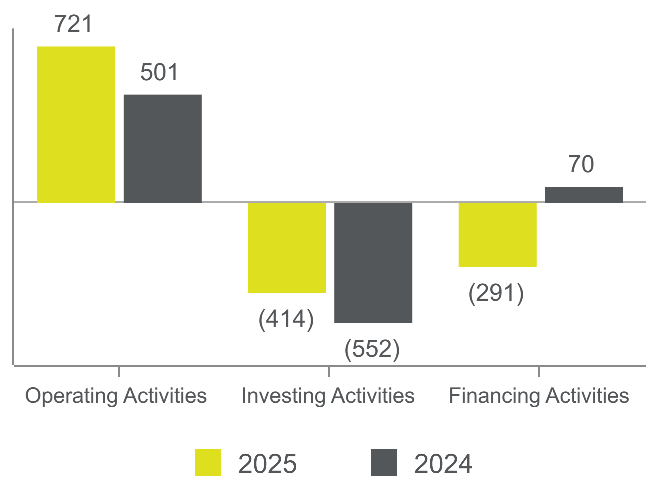
Dividend and Return of Capital
(in millions of Canadian dollars)



CAPEX, Net of Contributions
(in millions of Canadian dollars)



Cashflow Overview
(in millions of Canadian dollars)



Selected Annual Financial Information

The following table presents selected annual financial information for the years ended December 31, 2025 and 2024. This information is derived from the Corporation's Consolidated Financial Statements.

(in millions of Canadian dollars)	2025	2024*	Change %
Year Ended December 31,			
Revenue	4,536	4,351	4 %
Cost of power	3,523	3,356	5 %
Operating expenses	444	448	(1)%
Depreciation and amortization	203	204	— %
Net finance costs	105	108	(3)%
Net income	227	167	36 %
As at December 31,			
Total assets	6,851	6,611	4 %
Loans and borrowings	2,775	2,874	(3)%
Total liabilities	4,814	4,725	2 %
Shareholder's equity	2,037	1,886	8 %

*The comparative information has been re-presented due to the discontinued operation. Refer to Note 7 of the Consolidated Financial Statements.

The Corporation's most recent Consolidated Financial Statements are available on its website at www.alectra.com/investor-relations.

Corporate Overview

Alectra Inc. ("Alectra") is an investment holding company with a head office in Mississauga, Ontario. Alectra is indirectly owned through holding companies by eight shareholders: the City of Barrie; the City of Hamilton; the City of Markham; the City of Mississauga; the City of St. Catharines; the City of Vaughan; the City of Guelph; and BPC Energy Corporation.

Our Vision, Mission, and Values

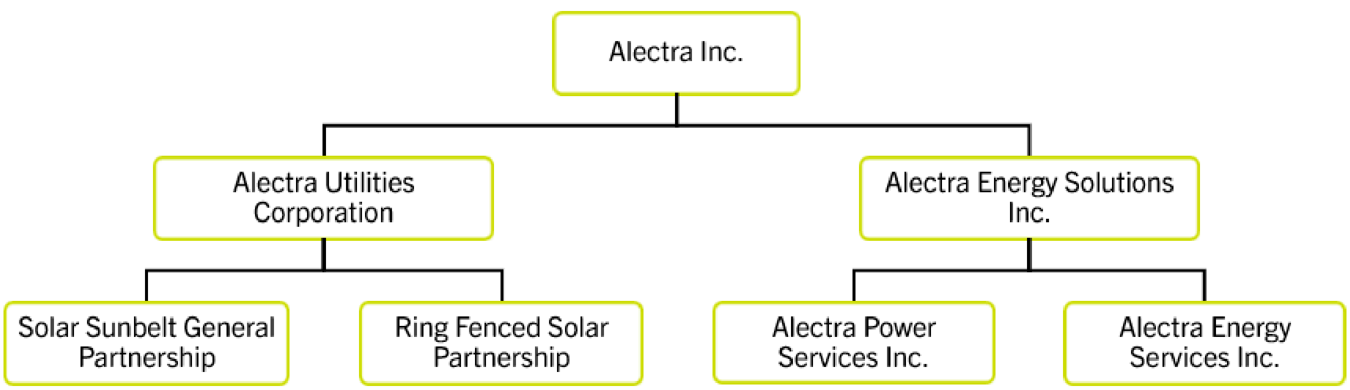
Vision: *We will be your trusted energy partner empowering a sustainable and brighter future.*

Mission: *To provide innovative and reliable energy solutions which deliver lasting value for all.*

Values: *Safety, customer focus, respect, excellence, and innovation.*

By integrating our people, processes, and systems, Alectra has emerged as one of Canada’s leading energy companies, driving energy innovation while maintaining a strong balance sheet and endeavoring to deliver maximum value for our employees, customers, shareholders, and communities.

Organization Structure



Refer to Note 1 of the Consolidated Financial Statements.

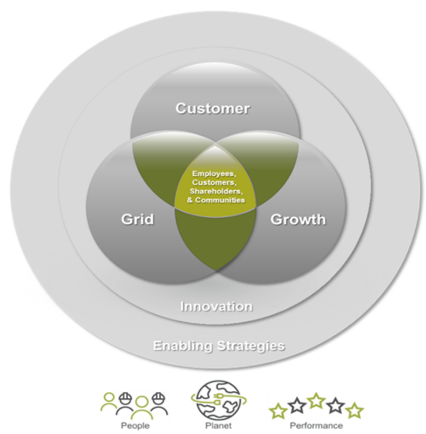
Corporate Overview (continued)

Vision and Strategic Intent

Alectra's vision is to be a trusted energy partner that enables a sustainable, resilient, and brighter future for the communities it serves. As the electricity sector undergoes a profound shift, from a traditional, centralized, one-way system to one that is increasingly customer-driven, distributed, and digitally integrated, Alectra is positioning itself to lead this transition.

"Strategy 2.0" was designed to be a natural evolution of Alectra's initial post-merger strategy, anchoring the organization around three core strategic pillars:

- Customer (Experience) - Improving service, building stronger customer relationships and understanding of their needs, and creating a digital experience.
- Grid (Modernization) - Adapting to the news of the future, while ensuring reliability for today, a digital grid.
- Growth (Enterprise) - Seeking new opportunities in distribution and energy solutions.



These core strategic pillars are intertwined and supported by four enabling strategies: culture and transformation, digital and innovation, advocacy as well as financing, which will provide Strategy 2.0 with greater reliability and resiliency.

As a sustainable organization Alectra remains committed to meeting the needs of current and future generations by empowering customers, communities, and employees; protecting the environment; and embracing innovation.

AlectraCARES is the Corporation's overarching sustainability framework, embedding People, Planet, and Performance into its core strategy and operations to create enduring value.

For further details on the values and the mission of Alectra, please review Alectra’s latest Annual Environmental Social and Corporate Governance Reports on the Corporation's website at:
https://www.alectra.com/esgreport

Regulated Business

Alectra Utilities Corporation

Alectra Utilities provides electricity distribution to over one million customers and is the largest municipally owned local distribution company ("LDC") in Canada by number of customers. In addition to its electricity distribution business, Alectra Utilities also has a competitive commercial rooftop solar photovoltaic generation business under which it develops, constructs, owns, finances, and operates rooftop photovoltaic generation equipment. The electricity generated by the Solar Photovoltaic Business is sold to the Independent Electricity System Operator ("IESO") under its Feed-In-Tariff long-term power purchase agreements.

Industry Regulation

The Corporation, through Alectra Utilities, is regulated by the OEB. In its capacity to approve or set rates, the OEB has the authority to specify regulatory accounting treatments that differ from IFRS. The regulatory accounting treatments of the OEB require the recognition of regulatory assets and liabilities which do not meet the definition of an asset or liability under IFRS.

Rate Setting

The electricity distribution rates and other regulated charges of the Corporation are determined in a manner that provides shareholders of the Corporation with opportunity to earn a regulated Maximum Allowable Return on Equity on the amount of shareholders' equity supporting the business of electricity distribution, which is also determined by regulation.

The rate-making policies of the OEB are guided by its statutory objectives under *The Ontario Energy Board Act, 1998 (Ontario)* that include, among other matters, to support the cost-effective planning and operation of the electricity distribution network and to provide an appropriate alignment between a sustainable, financially viable electricity sector and the expectations of customers for reliable service at a reasonable price.

The OEB regulates the electricity distribution rates charged by LDCs, such as Alectra Utilities, through periodic rate applications to the OEB and its ongoing monitoring and reporting requirements. At present, LDCs may apply to the OEB for electricity distribution rates under options specified in its *Report of the Board - A Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach* ("RRF"). The three rate-setting methods available to LDCs under the RRF are Price Cap Incentive Rate-setting ("Price Cap IR"), Custom Incentive Rate-setting ("Custom IR"), or Annual Incentive Rate-setting Index ("Annual IR"). These methods are described in more detail in the Consolidated Financial Statements.

Regulated Business (continued)

Rate Setting (continued)

The Incremental Capital Module ("ICM") is available to distributors operating under the Price Cap IR method and is designed to address capital investment needs that arise during the rate-setting term and exceed the OEB's materiality threshold. To qualify for ICM funding, a distributor must demonstrate that the requested amount is incremental to its capital requirements supported by existing rates and meets the OEB's criteria of materiality, need, and prudence. For distributors in an extended rebasing deferral period following utility consolidations (i.e., years six to ten of the deferral period), the OEB permits ICM funding requests for annual capital programs. Distributors seeking incremental capital relief must provide comprehensive evidence supporting the need, including the calculation of a rate rider to recover incremental revenue from each applicable customer class. Incremental revenues are recognized in the year the related ICM assets are expected to enter service, aligning recovery with the timing of benefits to customers and the expected approval of ICM rate adjustments.

Alectra Utilities is required to charge its customers for the following amounts, all of which other than distribution rates, represent pass-through charges to third parties:

- Commodity Charge - represents the market price of electricity consumed by customers and is remitted through the IESO to operators of generating stations. This charge includes the Global Adjustment, which reflects the difference between the market price of electricity and the rates paid to regulated and contracted generators.
- Retail Transmission Rate - reflects the costs of transmitting electricity from generating stations to local distribution systems. These charges are passed through to transmission facility operators.
- Wholesale Market Service Charge ("WMS") - covers a range of wholesale market support costs, including the IESO's costs to administer the electricity market, operate the provincial grid, and maintain system reliability. These amounts are remitted to the IESO.
- Distribution Rate - recovers the costs incurred by Alectra Utilities to deliver electricity to customers, including the OEB-approved cost of capital. Distribution rates, regulated by the OEB, consist of fixed and variable (usage-based) components and are set using a forecast of customer count and load.

Rate Applications

2025 Rate Applications

On August 15, 2024, Alectra Utilities filed an application for all five predecessor utility rate zones for the approval of 2025 electricity distribution rates and other charges, effective January 1, 2025. On December 12, 2024, the OEB issued its Decision and Rate Order on the Price Cap IR application, approving a 3.3% rate adjustment to distribution rates effective January 1, 2025, and providing for disposition of deferral and variance account balances.

2026 Rate Application

On August 14, 2025, Alectra Utilities filed an application for all five predecessor utility rate zones for the approval of 2026 electricity distribution rates and other charges, effective January 1, 2026. On December 16, 2025, the OEB issued its Decision and Rate Order on the Price Cap IR application, approving a 3.4% rate adjustment to distribution rates effective January 1, 2026, and providing for disposition of deferral and variance account balances.

Regulated Business (continued)

Rate Applications (continued)

2027 - 2031 Rate Application

Alectra Utilities filed a Custom IR application on October 14, 2025 for the 2027 to 2031 period. The application outlines proposed electricity distribution rates intended to meet evolving customer needs and support the continued delivery of reliable and efficient service across the communities it serves. The five-year plan focuses on:

- renewing and replacing aging and deteriorating infrastructure;
- meeting customer requirements and supporting municipal growth through system expansion and modernization; and
- strengthening system resilience against extreme weather events and cybersecurity threats to maintain a safe and reliable distribution network.

As part of the application, Alectra Utilities requested OEB approval to harmonize electricity distribution rates and other related charges (including retail transmission rates, low voltage rates, loss factors, and transformer allowance) across all legacy rate zones into a single Alectra Utilities-wide rate zone.

Refer to https://www.alectrautilities.com/regulatory-affairs/ for the status of the Corporation's rate applications.

Select Energy Policies and Regulation Affecting the Corporation

Ontario Energy Board Initiatives and Consultation:

- Cost of Capital – OEB Generic Hearing – In March 2024, the OEB initiated a generic hearing to review the methodology for determining cost of capital parameters and the deemed capital structure used in utility rate-setting. In March 2025, the OEB issued its Decision, establishing a revised methodology for calculating the cost of capital on a go-forward basis. Effective January 1, 2025, the OEB updated the parameters as follows: the Return on Equity (“ROE”) was reduced to 9.00% (from 9.25%), the deemed long-term debt rate to 4.51% (from 4.66%), and the deemed short-term debt rate to 3.91% (from 5.04%). The deemed capital structure remains unchanged at 56% long-term debt, 4% short-term debt, and 40% equity. The short-term debt rate will be set using the Bloomberg 3-Month Utility Bond Yield Index. Future annual updates to cost of capital parameters will follow a formula-based adjustment mechanism aligned with directional movements in long Canada Bond rates and Utility Bond Yield spreads. The OEB has committed to another review of the cost of capital within five years.

Regulated Business (continued)

Select Energy Policies and Regulation Affecting the Corporation (continued)

- System Expansion for Housing Developments – In June 2025, the OEB introduced the Capacity Allocation Model ("CAM") to facilitate housing development connections. The CAM applies to areas where there are multiple developers, large capacity expansions due to significant residential growth, and where there is substantial paid or agreed financial commitments to build. The framework is intended to allocate expansion costs fairly among all benefiting parties, rather than burdening the initial developer. Distributors will be responsible for planning and managing capacity allocations based on committed and forecast needs.

- Reliability & Power Quality – In early 2025, the OEB implemented minimum customer communication standards for use during extended electrical service interruptions caused by severe weather events. The OEB also updated its reliability performance target-setting methodology to promote continuous improvement. Beginning in 2027, reliability targets (SAIDI and SAIFI) will be based on each distributor's five-year average, adjusted for historical performance trends and peer benchmarking. Utilities can propose alternative custom targets in their rate rebasing, if supported by appropriate evidence.

- Vulnerability & System Hardening ("VASH") – In October 2025, the OEB released its final VASH Report, requiring distributors to incorporate climate resilience considerations, including vulnerability assessments and system-hardening investments, into their system planning and rate applications. The Toolkit provides models and resources to assess extreme weather risks using a benefit-cost framework. These requirements will be mandatory for rates set beginning in 2028.

- Framework for Energy Innovation 2.0 – Non-Wires Alternatives Incentives - In November 2025, the OEB established a new incentive mechanism under the Framework for Energy Innovation 2.0 to encourage the use of distributed energy resources ("DERs") as non-wires alternatives. Under the policy, distributors may earn a margin, set at a default rate of 25%, on payments made to third-party DER providers when those resources are used to meet a distribution system need. The incentive is designed to promote innovative, cost-effective system solutions and increase the utilization of DERs.

Competitive Business

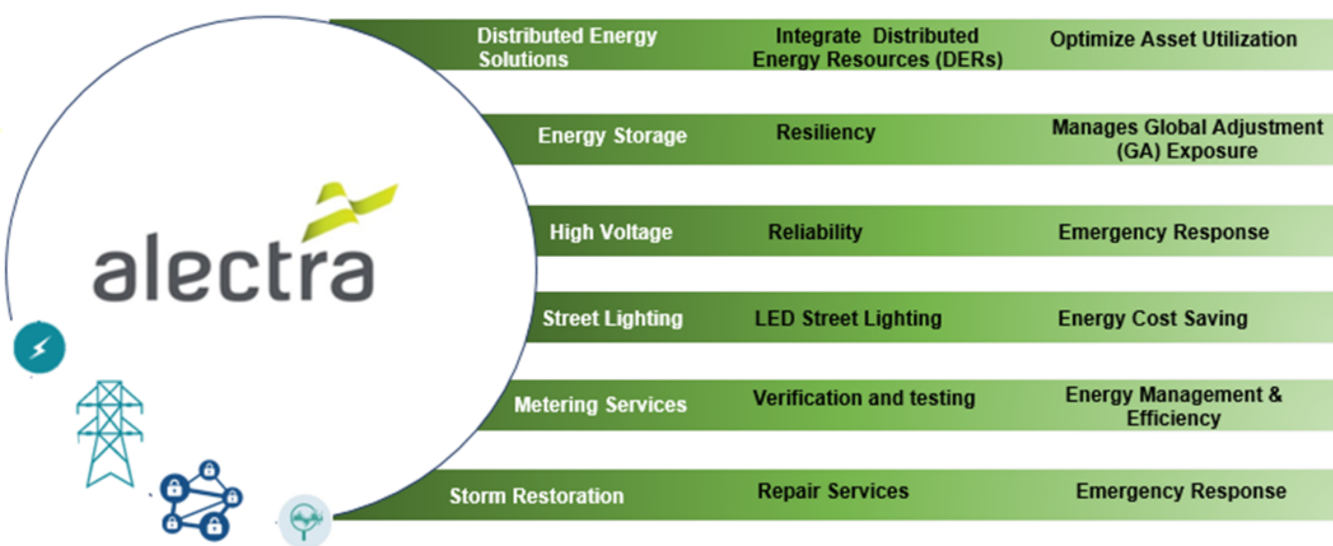
Alectra Energy Solutions Inc. ("AES") is a competitive energy services company owned by Alectra that provides innovative energy solutions including power services, street lighting, distributed energy solutions, energy storage, wholesale metering and emergency power restoration to institutional, commercial, and industrial customers. AES provides effective solutions to its customers through the use of current and emerging technologies, and empowers businesses and communities with efficient energy solutions that offer more choices and deliver sustainable value.

Subsidiaries and Joint Venture of AES

- Alectra Power Services Inc. ("APSI") provides street lighting services including design, construction, and maintenance.
- Util-Assist Inc. provides consulting services with respect to advanced metering systems procurement and implementation; customer information systems procurement and implementation; billing and meter data exception management services; an outage management call centre ("PowerAssist"); and other smart grid applications and services.
- Alectra Microgrid Master Limited Partnership provides energy management services which includes installing, owning, and operating an industrial energy storage battery and gas system while providing services to third parties.
- Holland Power Services Inc. ("HPSI") and 748953 N.B. Ltd provide emergency power restoration services to utilities primarily located along the eastern seaboard of the United States and Canada, and also provide industrial electrical services to utilities and industrial clients.
- Alectra Convergent ELT-1 Development Holdco Inc., a joint venture in which Alectra Energy Services Inc. ("AESI") owns a 50% share, provides distributed energy solutions which includes developing, constructing, commissioning, owning, operating and maintaining front-of-the-meter storage system projects in Ontario.

Key Business Updates

AES provides opportunities for customers to find energy solutions that fit their needs through services offered in each of its key divisions.

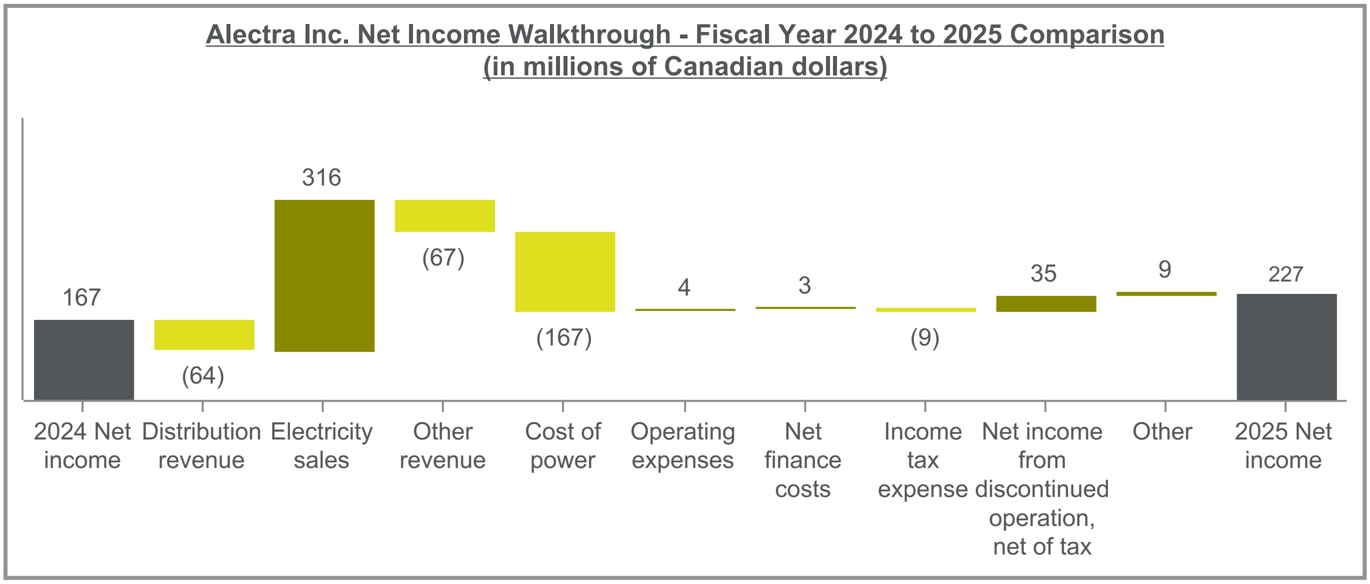


Competitive Business (continued)

Discontinued Operation

On October 1, 2025, AESI completed the sale of the submetering assets. The submetering business was established in 2013 and operated as a business unit under the legal entity AESI. The business offered customized residential and commercial submetering and billing solutions to developers, condominium boards, property managers, and property owners across Canada. Refer to Note 7 of the Consolidated Financial Statements.

Results of Operations



Year ended December 31, *($ millions, except as indicated)*	**2025**	2024	Change	
Net Income	**$227**	$167	$60 ↑	36%

Net income for the year ended December 31, 2025, was $227 and $60 higher than 2024 net income of $167. The increase in net income is principally attributable to:

i. higher electricity sales ($316) driven by higher electricity rates and higher electricity consumption;
ii. higher net income from discontinued operations, net of tax ($35) due to the gain recognized on sale of submetering assets; partially offset by
iii. higher cost of power ($167) primarily due to higher electricity consumption and higher electricity rates;
iv. lower other revenue ($67) mainly due to lower power restoration services revenue in the competitive business due to fewer storm events in 2025; and
v. lower distribution revenue ($64) mainly due to lower collection of rate riders; partially offset by higher distribution service rates, and higher consumption.

Results of Operations (continued)

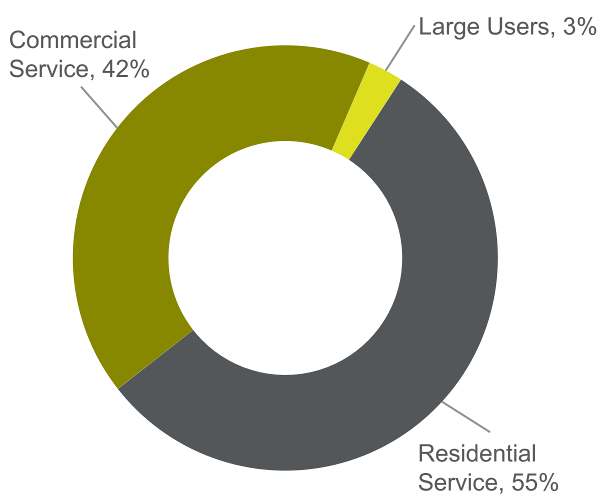
Net Income Variance Analysis

The significant drivers contributing to the change in net income are discussed in further detail below:

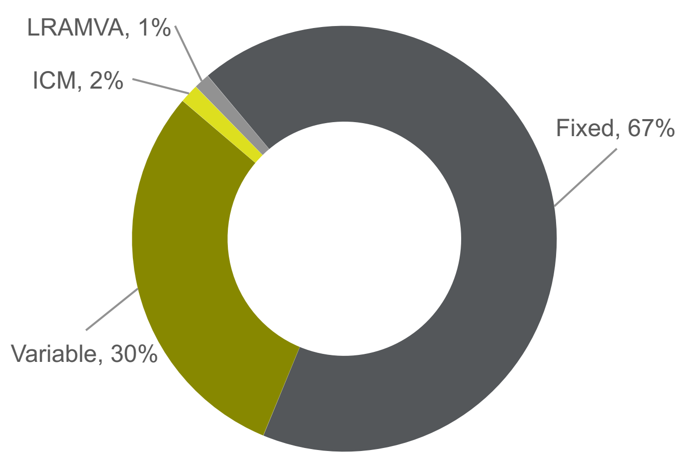
Distribution Revenue

Distribution revenue is recorded in accordance with OEB-approved distribution rates, which are set to recover the costs of operating and maintaining Alectra Utilities' electricity distribution system.

2025 - Actual Distribution Revenue by Customer Class



2025 - Actual Fixed vs. Variable Distribution Revenue



Alectra Utilities' customer classes are as follows:

- Residential service refers to electricity service provided for domestic or household purposes. This class includes single-family homes, individually metered multi-family units, and seasonal residential premises;
- Commercial service refers to electricity service provided to all premises that do not fall under the Residential or Large User classes. This category typically includes small businesses and bulk-metered multi-unit residential buildings. Customers in this class have a monthly peak demand of less than 5,000 kW, averaged over a 12-month period; and
- Large users refers to electricity service provided to customers with a monthly peak demand of 5,000 kW or greater, averaged over a 12-month period.

Year ended December 31, *($ millions, except as indicated)*	**2025**	2024	Change	
Distribution Revenue	**$733**	$797	$64 ↓	8%

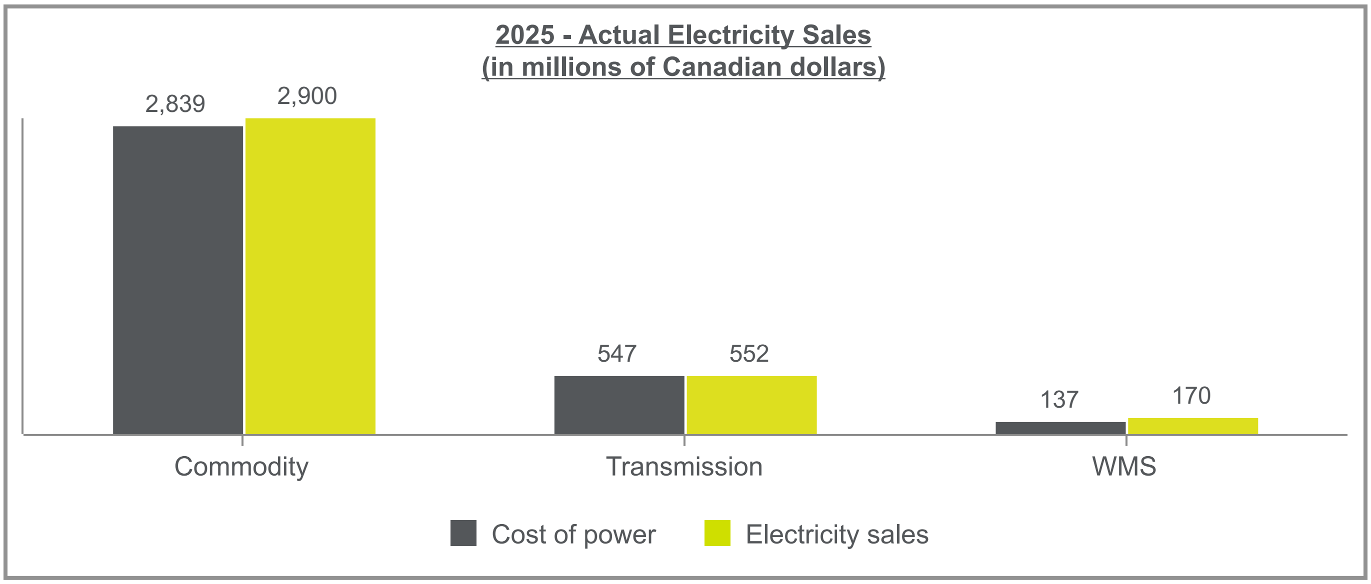
The decrease in distribution revenue of $64 is mainly attributable to: (i) lower collection of rate riders ($91); partially offset by (ii) higher OEB approved distribution rates driven by a higher inflation factor and higher customer consumption ($27).

Results of Operations (continued)

Net Income Variance Analysis (continued)

Electricity Sales

Electricity sales arise from the Corporation's responsibility to bill customers for electricity generated by third parties and for the related costs of providing electricity service. The amounts billed to the Corporation for electricity generation by the IESO and Hydro One Networks often differ from the amount recovered from customers. The resulting difference between electricity sales and the corresponding cost of power represents a timing variance that is ultimately recoverable from or refundable to, ratepayers through the Corporation's annual OEB rate applications. Timing variances that exist at the end of the prior fiscal year are generally settled over the twelve-month period following the effective date of the annual rate order, and more broadly within the thirteenth to twenty-fourth month after year-end.



Year ended December 31, *($ millions, except as indicated)*	**2025**	2024	Change	
Electricity Sales	**$3,622**	$3,306	$316	↑ 10%

The increase in electricity sales of $316 is mainly driven by: (i) higher electricity prices ($218); and (ii) higher electricity consumption in the current year ($98).

Results of Operations (continued)

Net Income Variance Analysis (continued)

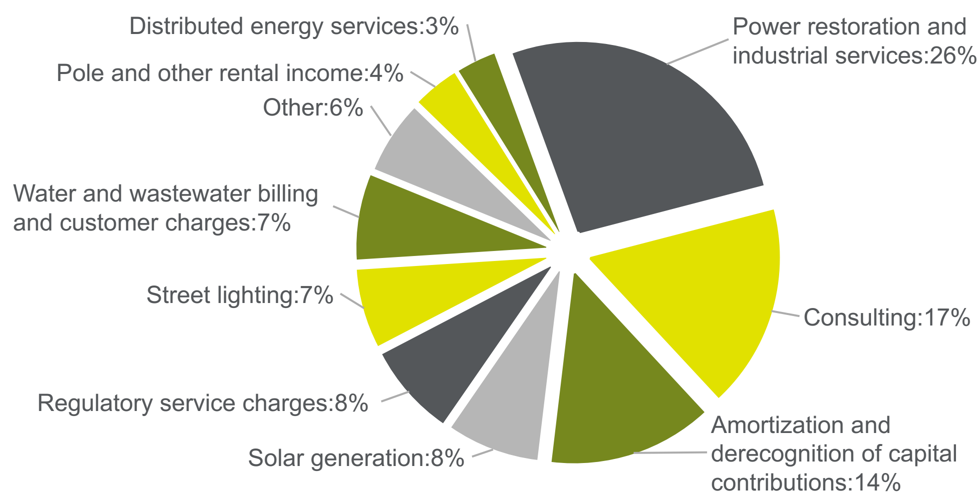
Other Revenue

Other revenue is generated from both regulated electricity distribution activities and competitive business operations.

Regulated sources include the amortization and derecognition of capital contributions, regulatory service charges such as fees for connections, reconnections, late payment charges and other ancillary services, water and wastewater billing and customer charges, and pole and other rental income earned from third parties that attach equipment to Alectra Utilities' poles.

Competitive sources of other revenue include power restoration and industrial services, consulting services, solar generation revenue, street lighting and related ancillary services, distributed energy services, and metering services.

2025 - Other Revenue



Note - submetering and metering services revenue is included in the note 7 'discontinued operation' in the Consolidated Financial Statements.

Year ended December 31, *($ millions, except as indicated)*	**2025**	2024	Change	
Other Revenue	**$181**	$248	$67	↓ 27%

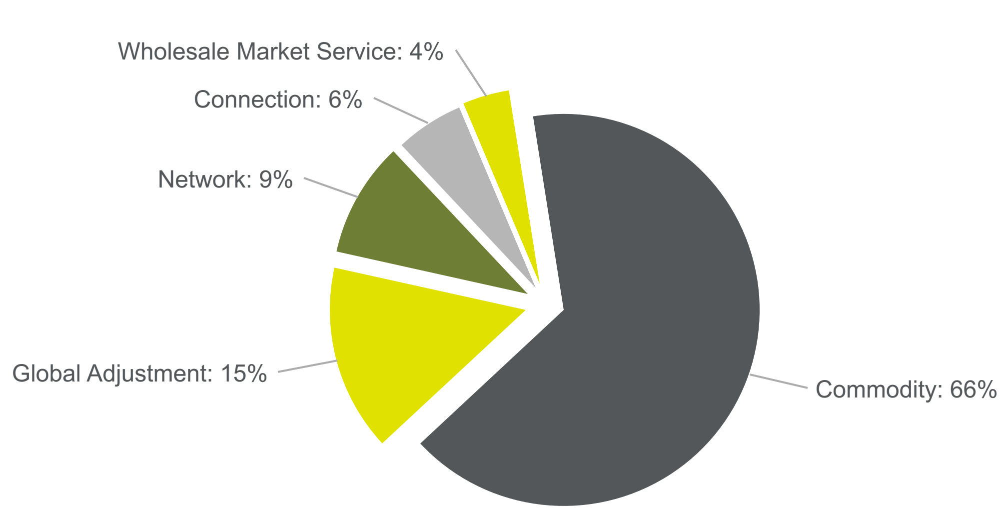
Other revenue decreased by $67 mainly due to: (i) reduction in power restoration services revenue in the competitive business due to as fewer storm events in 2025 ($79); partially offset by (ii) an increase in consulting revenue ($6).

Results of Operations (continued)

Net Income Variance Analysis (continued)

Cost of Power

Cost of power reflects the actual amounts charged by third-party electricity generators for energy delivered through Alectra Utilities and subsequently passed through to customers as energy sales.



Year ended December 31, *($ millions, except as indicated)*	**2025**	2024	Change	
Cost of Power	**$3,523**	$3,356	$167 ↑	5%

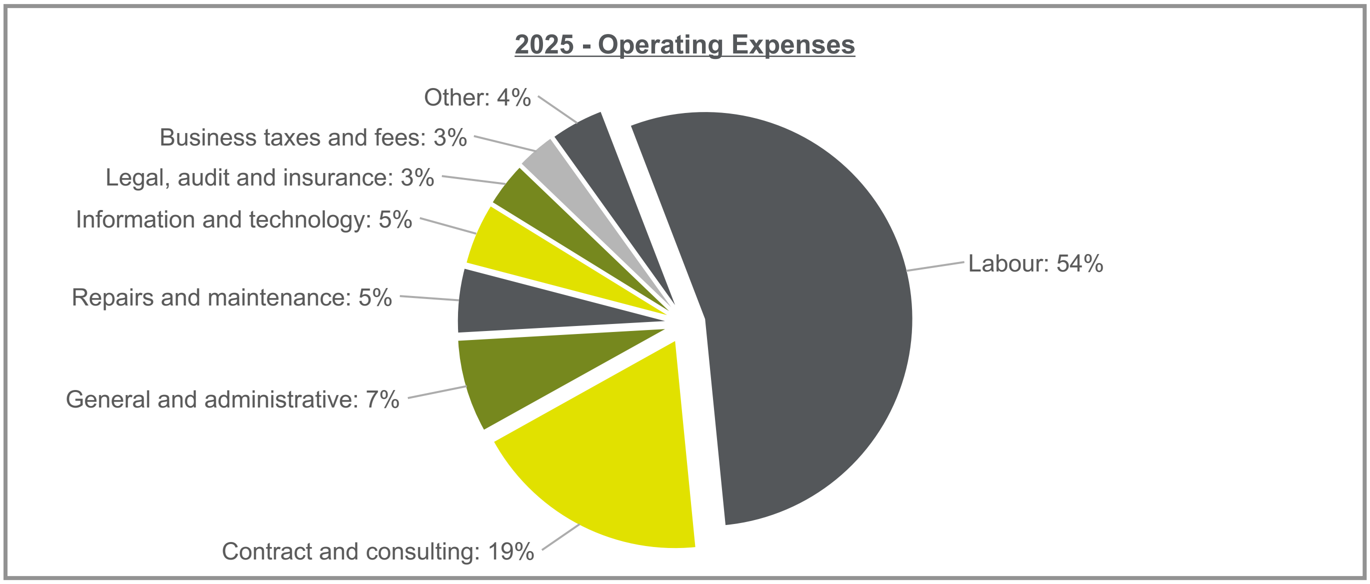
The increase in cost of power by $167 is due to: (i) higher electricity consumption ($95); and (ii) higher electricity prices ($72).

Results of Operations (continued)

Net Income Variance Analysis (continued)

Operating Expenses

Operating expenses primarily include labour, contract and consulting services, general and administrative costs, repairs and maintenance, information and technology costs, and other third-party service expenditures that support the Corporation's operations.



Year ended December 31, ($ millions, except as indicated)	**2025**	2024	Change	
Operating expenses	**$444**	$448	$4 ↓	1%

The decrease in operating expense of $4 is primarily driven by: (i) lower labour cost resulting from reduced storm response activity ($36); partially offset by (ii) higher salary and benefit costs due to increased salaries and increased headcount in Alectra Utilities ($12); and (iii) higher reactive cable repairs, credit losses, and environmental expenses in Alectra Utilities ($6).

Net Finance Costs

Net finance costs include interest expense on the Corporation's short-term and long-term borrowings, net of interest income.

Year ended December 31, ($ millions, except as indicated)	**2025**	2024	Change	
Net finance costs	**$105**	$108	$3 ↓	3%

The decrease in net finance costs of $3 is primarily due to: (i) lower short-term borrowing interest rates ($9); partially offset by (ii) higher average long-term borrowings ($8).

Results of Operations (continued)

Net Income Variance Analysis (continued)

Other

Other includes gain (loss) on the fair value of contingent consideration, loss on derecognition of property, plant and equipment and intangible assets, depreciation and amortization, foreign exchange loss, and share of net loss of joint ventures.

The significant variances within this category are as follows:

Year ended December 31, ($ millions, except as indicated)	**2025**	2024	Change	
Gain (loss) on fair value of contingent consideration	**$1**	($4)	$5 ↑	125%

The gain on fair value of contingent consideration of $5 is attributable to the updated valuation of the provision for the expected earnout payment to the former owner of Gagnon Line Construction Inc. Refer to Note 14 of the Consolidated Financial Statements.

Year ended December 31, ($ millions, except as indicated)	**2025**	2024	Change	
Loss on derecognition of property, plant and equipment and intangible assets	**$7**	$12	$5 ↓	42%

The decreased loss on the derecognition of property, plant and equipment and intangible assets of $5 is mainly due to fewer distribution assets removed from service.

Income Tax Expense

The Corporation, Alectra Utilities, AES, and APSI are exempt from income taxes under the Income Tax Act (Canada) and the Ontario Corporations Tax Act (collectively, the 'Tax Acts'). Accordingly, the Corporation, Alectra Utilities, AES and APSI are required to make payments in lieu of income taxes ('PILs') to the Ontario Electricity Finance Corporation ('OEFC'), which are calculated in accordance with the Tax Acts and applied to reduce certain debt obligations of the former Ontario Hydro continuing in OEFC. The remaining subsidiaries of the Corporation are subject to taxation under the Tax Acts, with income tax expense comprising current and deferred tax.

Year ended December 31, ($ millions, except as indicated)	**2025**	2024	Change	
Income tax expense	**$70**	$61	$9 ↑	15%

The increase in income tax expense by $9 primarily relates to higher net income before tax ($8).

Net Income from Discontinued Operation , Net of Tax

Year ended December 31, ($ millions, except as indicated)	**2025**	2024	Change	
Net income from discontinued operation, net of tax	**$44**	$9	$35 ↑	389%

The increase in net income from discontinued operation, net of tax by $35 is primarily due to the gain on sale of the Submetering assets within the competitive business.

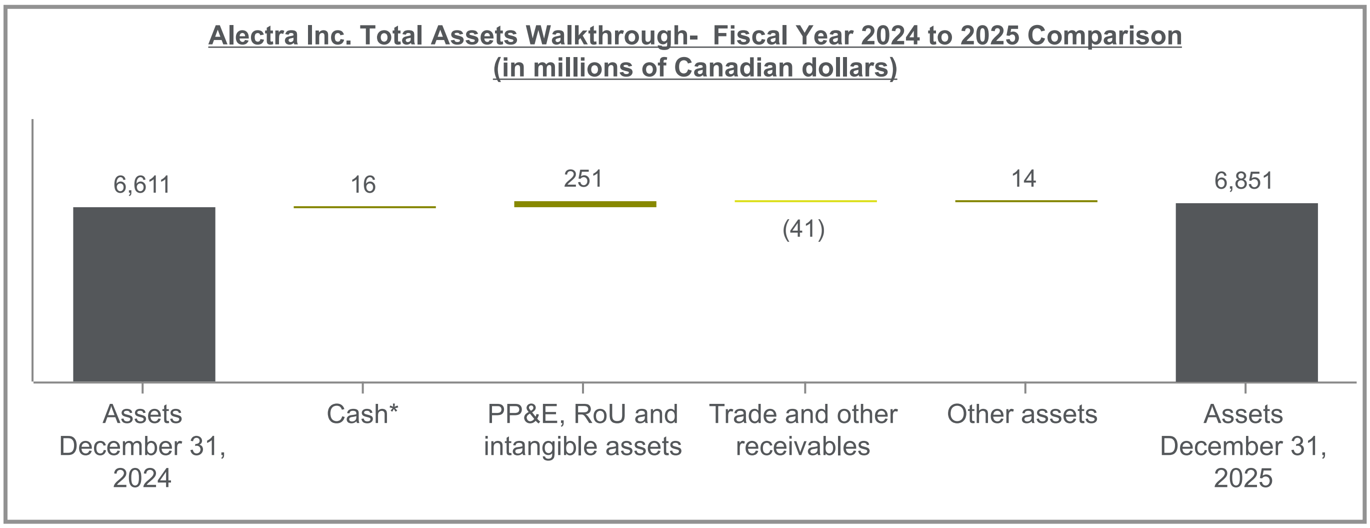
Results of Operations (continued)

Competitive Business Net Income Variance Analysis

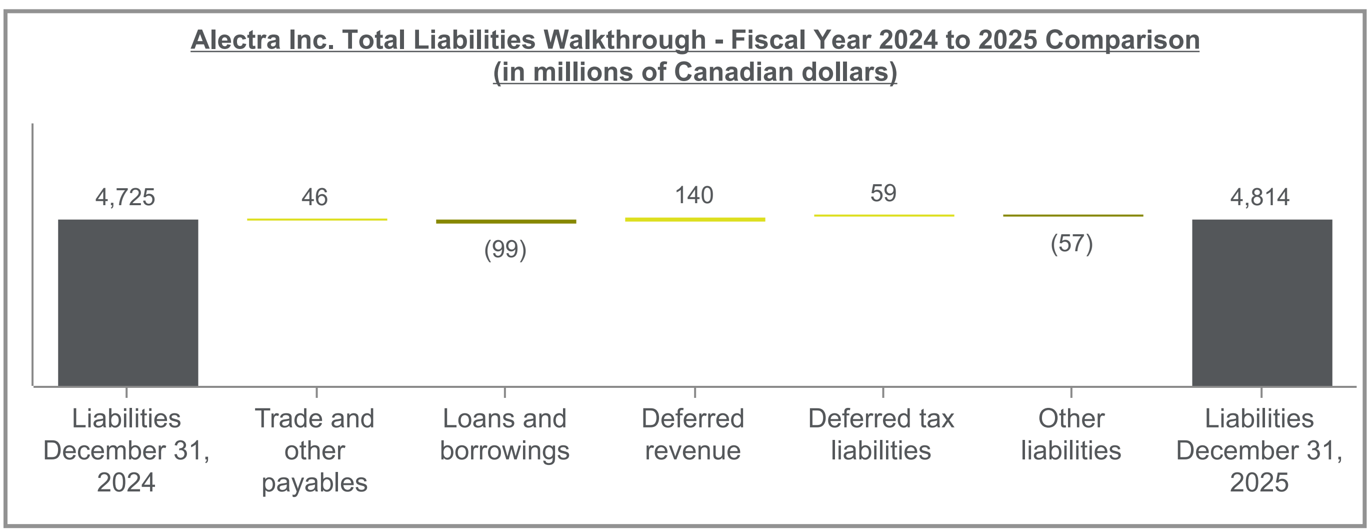
Year ended December 31, *($ millions, except as indicated)*	**2025**	2024	Change	
AES Net Income	**$15**	$18	$3 ↓	17%

The decrease in net income of $3 is primarily due to: (i) lower revenue net of cost of services rendered due to reduced storm response activities ($43); partially offset by (ii) higher net income from discontinued operation, net of tax, resulting from the gain on the sale of Submetering assets ($35).

Financial Position



*For details, refer to the Liquidity and Capital Resources section.



For details, refer to the Consolidated Financial Statements.

Financial Position (continued)

Significant year over year changes in the Corporation's assets and liabilities as at December 31, 2025, are as follows:

Assets	$ Change (millions)	% Change	Trend	Explanation
PP&E, RoU and intangible assets	251	4 %	↑	The increase is primarily driven by: (i) in-service additions of distribution system and computer software assets; (ii) investments in land, buildings, fleet and IT assets; partially offset by (iii) disposals of meters associated with the discontinued operation in the competitive business; (iv) disposals of retired distribution assets; and (v) higher accumulated depreciation.
Trade and other receivables	(41)	(6)%	↓	The decrease is primarily due to: (i) lower storm response activities in the competitive business; (ii) lower energy bill receivables due to timing; and (iii) lower trade receivables and unbilled revenue due to the derecognition of receivable resulting from the discontinued operation; partially offset by (iv) higher unbilled revenue due to higher consumption and higher average energy prices.
Other assets	14	12 %	↑	The increase is primarily due to (i) increase in income tax receivable; and (ii) higher investment in a joint venture in the competitive business.

Liabilities	$ Change (millions)	% Change	Trend	Explanation
Deferred revenue	140	17 %	↑	The increase is primarily driven by (i) additional customer contributions received for customer connections projects; and (ii) additional contributions for transit projects.
Loans and borrowings	(99)	(3)%	↓	The decrease is primarily due to lower short-term borrowings required to fund working capital and general corporate requirements.
Deferred tax liabilities	59	32 %	↑	The increase is primarily driven by (i) increased regulatory balances; and (ii) higher temporary differences associated with PP&E and intangible assets.

Liquidity and Capital Resources

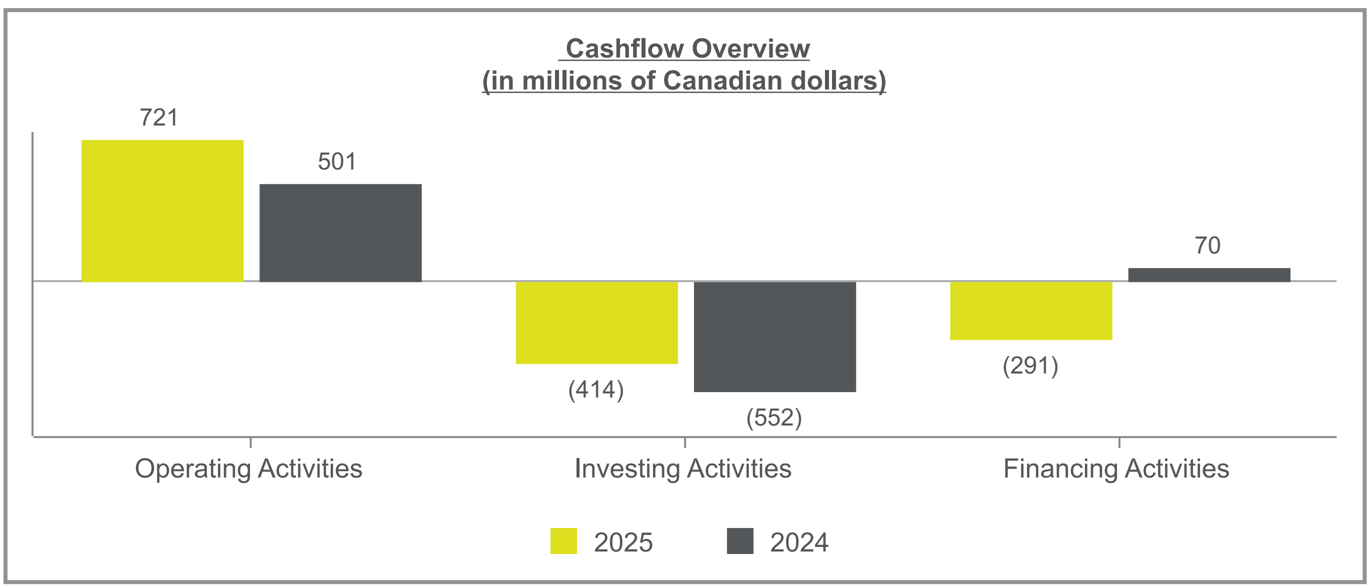
Sources of Liquidity and Capital Resources

The Corporation maintained a strong liquidity position in 2025, supported by improved operating cash flows, lower short-term borrowing requirements, and continued access to committed credit facilities and capital markets.

The Corporation's current ratio (current assets over current liabilities) increased year over year from 0.75 in 2024 to 0.81 in 2025. This improvement was primarily driven by a reduction in short-term borrowings required to fund working capital and general corporate requirements, as well as a decrease in other current liabilities, mainly reflecting the release of a holdback payable in the competitive business. These favourable changes were partially offset by a decrease in trade receivables, largely attributable to lower revenue from storm response activities in the competitive business.

The Corporation uses its commercial paper ("CP") program as its primary source of short-term liquidity to fund working capital requirements, prior to accessing long-term debt markets. This approach allows the Corporation to maintain an efficient mix of short-term and long-term debt, reduce overall financing costs, and enhance borrowing flexibility. In addition to short-term liquidity, the Corporation continues to access long-term debt capital markets through the issuance of senior unsecured debentures, as required, to fund capital investment programs and refinance maturing debt.

Liquidity and capital resources are required primarily to support system expansion and enhancement expenditures to maintain and improve the reliability and service quality of the electricity distribution system, to fund energy purchases, and to meet working capital and other operational obligations. The Corporation's principal sources of liquidity and capital resources consist of funds generated from operating activities, supplemented by financing and investing activities.



Liquidity and Capital Resources (continued)

Sources of Liquidity and Capital Resources (continued)

Operating Activities

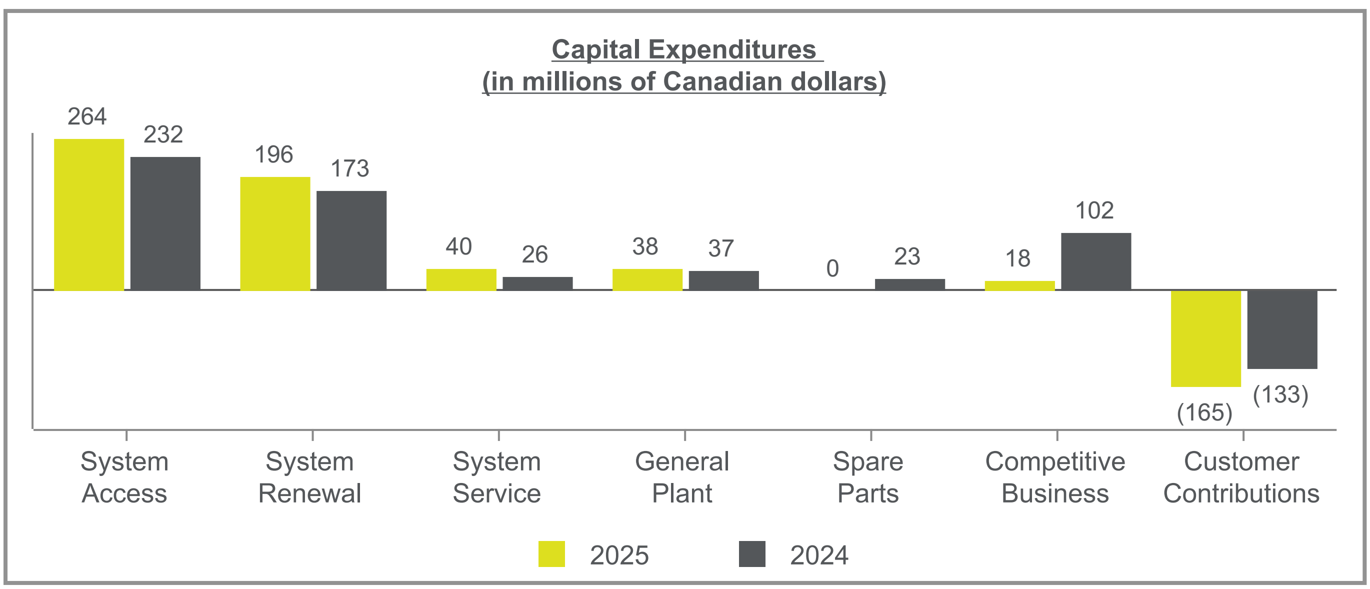
Net cash generated from operating activities increased by $220 in 2025 relative to 2024. This increase was mainly due to: (i) favourable changes in non-cash operating working capital, primarily reflecting movements in receivables and payables ($191); (ii) higher capital contributions received during the current year ($39); and (iii) higher earnings before interest, taxes, depreciation and amortization ("EBITDA") ($22); partially offset by (iv) the gain recognized on the sale of the discontinued operation (submetering assets) ($37).

Investing Activities

Cash used in investing activities decreased by $138 in 2025 compared to 2024. The decrease was primarily due to: (i) the cash proceeds received from the sale of the discontinued operation, net of transaction costs ($125); and (ii) acquisition of assets from GLC in the competitive business in 2024 ($49); partially offset by (iii) higher in-service additions of distribution assets ($44).

As the largest municipally-owned LDC in Canada providing service to over one million customers, the Corporation continues to invest in the renewal of existing aging infrastructure to address safety, reliability and customer service requirements.

The Corporation's gross capital investments and customer contributions are presented below:



Liquidity and Capital Resources (continued)

Sources of Liquidity and Capital Resources (continued)

Investing Activities (continued)

System Access expenditures relate to projects required to meet customer service obligations under the OEB's Distribution System Code and the Corporation's conditions of service. These projects include new customer connections, construction of distribution infrastructure for new subdivisions, and relocation of system plant to accommodate municipal roadway reconstruction and major transit initiatives. Capital expenditures in this category increased by $32 relative to 2024, primarily due to: (i) higher investment in distribution assets driven by municipal roadway reconstruction projects ($18); (ii) increased new connection activity associated with subdivision development and industrial, commercial, and institutional ("ICI") customers ($15); and (iii) greater investment in light rail transit expansion projects ($6); partially offset by (iv) lower investment related to large customer expansion projects across Alectra Utilities' service territory ($9).

System Renewal expenditures relate to long-term plans to replace assets that are at or nearing the end of their useful lives, with replacement strategies prioritized based on asset condition and reliability performance. Capital expenditures in this category increased by $23 relative to 2024, principally due to: (i) higher reactive expenditures associated with urgent, unplanned replacements of deteriorated assets ($15); and (ii) additional investments in overhead and underground infrastructure to improve the electrical system performance ($6).

System Service expenditures relate to projects that support the expansion, automation, and reliability of the distribution system. Capital expenditures in this category have increased by $14 relative to 2024, principally due to: (i) increased activity on capacity expansion projects ($9); and (ii) continued investment in the automation of electrical infrastructure ($4).

General Plant expenditures relate to information systems projects, facilities, and fleet. Capital expenditures in this category remained consistent with 2024.

Customer Contributions ("CC") relate to deposits in aid of the capital cost of construction. CC increased by $32 over the previous year, primarily due to higher System Access volumes associated with increased customer activity and municipal roadway projects.

Spare Parts ("SP") relate to transformers and meters which are held for use in operations. SP decreased by $23 relative to 2024, principally due to lower quantities purchased in the current year.

Capital expenditures in the competitive business decreased by $84 relative to 2024, primarily due to: (i) the one-time acquisition of assets from GLC and distributed energy resource ("DER") infrastructure in the prior year ($73); and (ii) reduced investment in metering hardware following the sale of the Submetering assets ($4).

Financing Activities

Cash used in financing activities decreased by $361 in 2025 compared to 2024. The decrease was primarily driven by: (i) the absence of debenture issuances in 2025, compared to issuances of $498 in 2024; and (ii) the repayment of short-term borrowings due to lower working capital requirements and improved operating cash flows ($180); partially offset by (iii) the repayment of an outstanding debenture and promissory notes in 2024 that did not recur in 2025 ($316).

Liquidity and Capital Resources (continued)

Credit Ratings

Credit ratings represent independent, forward-looking assessments of the Corporation's ability to meet its financial obligations and are not recommendations to buy, sell or hold securities. Ratings may be revised or withdrawn by the rating agencies at any time.

The following table sets out the current credit ratings of the Corporation as assigned by Dominion Bond Rating Service ("DBRS") Morningstar, Fitch and S&P Global Ratings.

	DBRS Morningstar		Fitch		S&P Global Ratings	
	Credit Rating	**Trend**	**Credit Rating**	**Outlook**	**Credit Rating**	**Outlook**
Issuer rating	A	Stable	A-	Negative	A-	Stable
Senior unsecured debentures	A	Stable	A	Negative	A-	Stable
Short-term (Commercial Paper)	R-1 (low)	Stable				

On June 20, 2025, Dominion Bond Rating Service ("DBRS") Morningstar confirmed the Corporation's "A" rating with a Stable trend for both the Issuer Rating and Senior Unsecured Debentures, as well as an R-1 (low) rating for commercial paper. DBRS Morningstar's confirmation of the Corporation's ratings reflects the strength of its regulated electricity distribution business, which provides predictable earnings and cash flows and continues to support the Corporation's credit profile. DBRS also notes that there were no material changes to the Corporation's business risk assessment, which continues to be supported by a reasonable regulatory framework. The Stable trend reflects DBRS Morningstar's financial risk assessment of the Corporation, which remains supportive of the current ratings.

On July 10, 2025, Fitch Ratings affirmed the Corporation's Long-Term Issuer Default Rating ("IDR") of "A-" and an instrument rating of "A" for the Corporation's senior unsecured debt. Fitch revised Alectra's outlook from Stable to Negative, reflecting their expectations of continued pressure on funds-from-operations leverage metrics due to the Corporation's significantly elevated capital expenditure ("CAPEX") program. The Corporation's Fitch ratings are supported by its large-scale regulated electric distribution operations in high-growth areas of Ontario. In addition, Fitch views the rate-setting mechanisms employed by the OEB as highly constructive. Fitch has applied a one-notch utility sector uplift from the IDR to the ratings of the Corporation's senior unsecured debt, reflecting the Corporation's financing policy of raising debt exclusively at the parent level and the expectation that its business mix will remain predominantly regulated.

On June 13, 2025, Standard & Poor's Global ("S&P") affirmed the Corporation's Corporate and Long-Term Credit Rating of "A-" with a Stable outlook. S&P's assessment reflects Ontario's highly credit-supportive regulatory environment, which underpins the Corporation's strong business risk profile. The rating also reflects the Corporation's lower-risk, regulated electric local distribution company business, which accounts for approximately 90% of consolidated EBITDA. The "A-" rating with a Stable outlook incorporates S&P's expectation of the Corporation's continued consistent financial performance.

Liquidity and Capital Resources (continued)

Requirements for liquidity resources

The Corporation has the following sources of liquidity that it may access from time to time to meet its funding requirements:

- Revolving credit facilities: Aggregate revolving unsecured credit facilities totaling $1,100, consisting of:
  - $900 committed revolving facility with a syndicate of five banks, maturing on November 28, 2030 ("Revolving Facility"). The committed revolving facility is also used to support outstanding commitments under the Corporation’s CP program through same-day market rate advances; and
  - a supplemental credit facility that provides support for up to $200.
- Senior unsecured debentures: Issuance of senior unsecured debentures with various maturity dates under established trust indentures.

The Revolving Facility contain certain covenants, including a requirement that the Corporation’s debt to capitalization ratio not exceed 75%. As at December 31, 2025, the Corporation was in compliance with all covenants included in its Revolving Facility agreement.

As at December 31, 2025, the Corporation was in compliance with all covenants included in its trust indentures.

Based on available committed credit facilities, ongoing access to capital markets, and internally generated cash flows, the Corporation believes it has sufficient liquidity and capital resources to meet its operational requirements, fund planned capital investments, and satisfy contractual obligations as they come due.

Short-term debt at December 31, 2025, and 2024 consists of CP issued under the Corporation's CP program. The short-term debt is denominated in Canadian dollars and is issued with varying maturities of less than one year. CP issuances bear interest based on the prevailing market conditions at the time of issuance. Outstanding CP issuance at December 31, 2025, was $355 (2024 - $455).

Long-term liquidity is available through the Corporation’s ability to issue senior unsecured debentures under an established Trust Indenture. The rates of interest on such debentures comprise: government of Canada bond yields with terms of maturity corresponding to the terms of issued debentures; market-based credit spreads determined with reference to comparably rated entities; and costs of issuance.

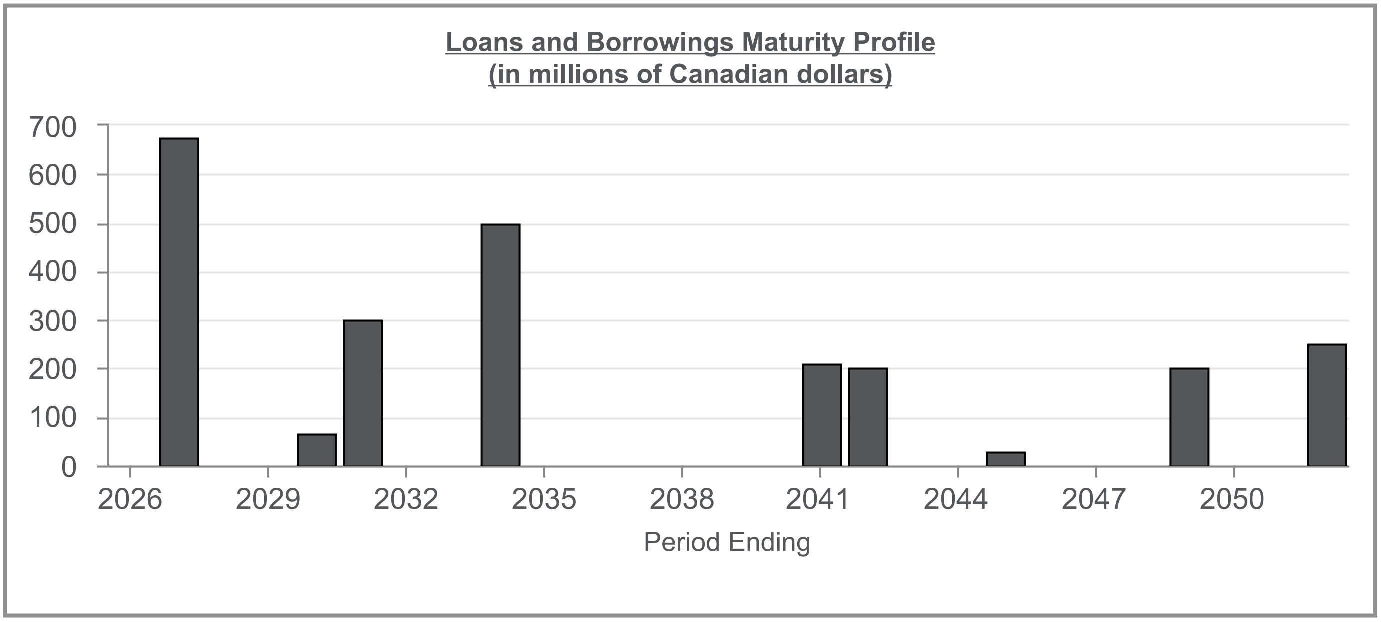
Refer to Note 13 of the Consolidated Financial Statements for details on the Corporation’s long-term borrowings.

The Corporation has sufficient liquidity to meet the needs of its ongoing commitment to maintain, improve and expand its distribution system and competitive businesses, and invest in other infrastructure assets on a sustainable basis.

Liquidity and Capital Resources (continued)

Loans and borrowings maturities

The following table presents a summary of the Corporation's loans and borrowings maturities:



Summary of contractual obligations and other commitments

The following table presents a summary of the Corporation's commercial paper, debentures, major contractual obligations, and other commitments:

For period ending, *($ millions, except as indicated)*	2026	2027	2028	2029	2030	After 2030	Total
Commercial paper	355	—	—	—	—	—	355
Debentures - principal repayment	—	675	—	—	65	1,690	2,430
Debentures - interest payments	87	80	71	71	71	733	1,113
Lease obligations	4	3	3	3	4	10	27
Capital expenditures/financial investments	257	7	3	—	5	—	272
Operating expenditures	42	6	2	1	7	—	58
Total contractual obligations and other commitments	745	771	79	75	152	2,433	4,255

Under Ontario electricity legislation and IESO market rules, the Corporation is required to provide financial security to cover its market obligations. This requirement is met through a letter of credit of $33 (2024 – $33), which the IESO may draw upon in the event of a payment default.

Share Capital

The Corporation's authorized share capital is comprised of an unlimited number of Class A through G voting common shares, and an unlimited number of Class S non-voting shares, all of which are without nominal or par value as follows:

As at December 31, *($ millions, except as indicated)*	**2025** Number of Shares	Amount	**2024** Number of Shares	Amount
Authorized				
Unlimited Class A through G common shares				
Issued and outstanding	10,485,000	953	10,485,000	953
Authorized				
Unlimited Class S shares				
Issued and paid				
Class S shares	99,999	22	99,999	25
Total share capital	10,584,999	975	10,584,999	978

An unlimited number of Class A through C special shares have been authorized but not issued.

The Alectra Inc. Dividend Policy was approved by shareholders and is incorporated into the Unanimous Shareholders' Agreement, dated January 1, 2019, as Schedule C.

The annual voting common dividend is targeted at up to 60% of the Corporation's annual consolidated Modified International Financial Reporting Standards ("MIFRS") net income, excluding the results from the former PowerStream Solar Business that accrue to the Solar shareholders on Class S shares.

The annual Class S share dividend is determined based on the "forecast annual net free cash flow" generated exclusively by the former PowerStream Solar Business. The dividend amount is set with consideration for maintaining adequate cash and credit metrics within the Solar business.

During the year ended December 31, 2025, the Corporation declared and paid dividends as follows:

- Common share dividends aggregating $78 or $7.51 per share (2024 - $81 or $7.70 per share); and
- Class S share dividends aggregating $1 or $5.76 per share (2024 - $1 or $14.72 per share).

In addition, a return of capital of $3 (2024 - $2) was declared and paid on Class S shares during the year.

Subsequent to the year end, on March 5, 2026, the Corporation declared a dividend in the amount of $43 on its common shares payable to its shareholders. The Corporation has also declared a return of capital in the amount of $1, payable to Class S shareholders.

The Class S share dividends, other than return on capital, are subject to Part VI.1 tax under the *Income Tax Act (Canada)* at a rate of 25% based on the amount of dividend paid. The Corporation is eligible for a corresponding deduction equal to a specified multiple of the dividend; however, this deduction does not fully offset the Part VI.1 tax, resulting in a net effective tax rate of 1.8% on the Class S share dividends.

For details, refer to Note 17 of the Consolidated Financial Statements.

Related Parties Balances and Transactions

Significant related party transactions and balances with related parties are as follows:

Year ended December 31, ($ millions, except as indicated)	2025	2024
Transactions		
Revenue	113	104
Expenses	5	6
Return of capital	3	2
Dividends declared and paid	79	82
Balances		
Due from related parties	17	18
Due to related parties	63	58

Services provided to the cities include electricity distribution, street lighting, road projects and water and sewage billing. Expenses incurred include municipal taxes and facilities rental.

The amount due to/from related parties consist of balances payable to/receivable from: the City of Barrie; the City of Guelph; the City of Hamilton; the City of Markham; the City of Mississauga; the City of St. Catharines; the City of Vaughan; and wholly-owned subsidiaries of related parties.

The annual compensation of key management personnel was $20 (2024 - $19).

For details, refer to Note 12 (b) of the Consolidated Financial Statements.

Material Accounting Policies and Critical Judgments and Estimates

The Corporation's accounting policies have been reviewed and approved by the Audit, Finance and Risk Management Committee and are outlined in Note 4 of the Consolidated Financial Statements.

These policies require management to make certain judgments, estimates, and assumptions that are inherently complex and subjective. Changes to these judgments, or to the underlying economic environment, such as those resulting from geopolitical events or uncertainty regarding economic growth, could significantly affect the Corporation's financial results. In future periods, such changes may necessitate adjustments to the carrying amounts of balances that are subject to estimates and judgments.

Judgments and estimates are often interrelated. Significant areas where management is required to make estimates and apply judgment in determining carrying values include asset valuation, unbilled revenue, contingent consideration, useful lives of assets, impairment, employee future benefits, provisions and contingencies, business combinations, revenue recognition, performance obligations, influence over investees, lease terms, and deferred taxes.

Future Accounting Changes

The IASB has issued amendments to IFRS 9, *Financial Instruments* and IFRS 7, *Financial Instruments Disclosures* effective January 1, 2026, which clarify the classification, measurement, and derecognition of certain financial instruments. These amendments are not expected to have a material impact on the Corporation's Consolidated Financial Statements. Additionally, IFRS 18, *Presentation and Disclosure in Financial Statements*, will be effective January 1, 2027. This new standard will significantly impact the presentation and disclosures in the Corporation's Consolidated Financial Statements. The Corporation does not intend to early adopt the standard. For details, refer to Note 5 of the Consolidated Financial Statements.

Non-IFRS Financial Measures

The Corporation uses certain non-IFRS financial measures to assess its operating performance, financial condition, and cash-generating ability. These measures include EBITDA, comparable net earnings, and adjusted funds from operations ("AFFO"), which are presented on a Modified International Financial Reporting Standards ("MIFRS") basis.

MIFRS adjusts IFRS-reported results to reflect the effects of rate regulation, consistent with the regulatory framework under which the Corporation operates. Management believes that these measures provide additional insight into the Corporation's underlying operating performance and financial results by better reflecting the economics of a rate-regulated environment.

These non-IFRS financial measures do not have standardized meanings prescribed by IFRS and may not be comparable to similar measures presented by other companies. Accordingly, these measures should not be considered in isolation or as a substitute for measures of financial performance prepared in accordance with IFRS.

EBITDA and Comparable Net Earnings

EBITDA is calculated as earnings before interest, income taxes, depreciation and amortization, and other items as presented in the reconciliation below.

Comparable net earnings represent net income adjusted for the effects of rate regulation and other items that management considers not reflective of the Corporation's underlying operating performance. This measure is used by management to assess performance trends and the sustainability of earnings over time.

Non-IFRS Financial Measures (continued)

EBITDA and Comparable Net Earnings (continued)

The following table provides a reconciliation of the Corporation's EBITDA under MIFRS to IFRS-reported results on a consolidated basis. These non-IFRS financial measures have been consistently applied in the current and prior periods.

Year ended December 31, *($ millions, except as indicated)*	**2025**	**2024**
EBITDA (MIFRS)	396	458
Add adjustments to remove regulatory accounting:		
Revenue	188	105
Operating expenses	(15)	(16)
EBITDA (IFRS)	569	547
Depreciation and amortization	(203)	(204)
Net finance costs	(105)	(108)
Foreign exchange loss	(1)	—
Loss on derecognition of property, plant, and equipment and intangible assets	(7)	(12)
Gain (loss) on fair value of contingent consideration	1	(4)
Share of net loss of joint ventures, net of tax	(1)	—
Income before income tax (IFRS)	253	219

AFFO

Adjusted funds from operations ("AFFO") is used as an additional measure of cash flow that excludes the impact of changes in the Corporation's non-cash working capital and is adjusted for contributions in aid of construction. The table below summarizes the Corporation's AFFO for the years ended December 31, 2025 and 2024.

Year ended December 31, *($ millions, except as indicated)*	**2025**	**2024**
IFRS net income	227	167
Adjustment for regulatory activities [1]	(83)	(28)
MIFRS net income	144	139
Depreciation and amortization	180	185
Foreign exchange loss	1	—
Net loss on derecognition of property, plant and equipment and intangible assets	6	10
(Gain) loss on fair value of contingent consideration	(1)	4
Share of net loss of joint ventures, net of tax	1	—
Gain on sale of discontinued operation, net of tax	(37)	—
Net change in non-cash operating working capital	69	(142)
Net change in non-current assets and liabilities	118	70
Net change in taxes	(30)	16
Total changes	307	143
AFFO	451	282

[1] Refer to Note 29 in the Consolidated Financial Statements.

Non-IFRS Financial Measures (continued)

AFFO (continued)

The increase in AFFO was mainly attributable to favourable changes in non-cash operating working capital, primarily driven by movements in payables and receivables and favourable changes in non-current assets and liabilities, mainly reflecting the net movement in regulatory assets and liabilities.

Risk Management and Risks

This section provides an overview of the Corporation's overall risk management approach, which is followed by a discussion of the specific risks that could adversely affect its business.

The Corporation is exposed to various risks and uncertainties that could impact the achievement of its strategy and potentially have a material adverse effect on its business. The Corporation's Enterprise Risk Management Program adopts an enterprise-wide approach to risk management, which is guided by an overall risk philosophy, to identify, assess, and mitigate risks to the business.

Risk management is the responsibility of all business units. There are strong governance practices in place to ensure consistent consideration of risks in all decision-making.

The Corporation's risk management governance structure is comprised of three key levels:

- The Board of Directors – maintains a general understanding of the Corporation's risk profile and philosophy as well as oversees the management of the Corporation's significant exposures.
- The Executive Committee – ensures systems are in place to manage and monitor risks and trends as well as to escalate key risks to the attention of the Board, as required.
- The Senior Leadership Team – supports the overall risk management program and actively engages in the day-to-day management of risks.

The section below discusses certain specific risks that could have a material adverse impact on the Corporation's business, financial condition, or results of operations and is not a comprehensive list of all the risks to the Corporation.

Regulatory & Compliance Risk

The Corporation operates within a regulated electricity industry and is subject to oversight by regulatory authorities and various levels of government. Actions taken by these bodies may affect the Corporation's business activities. Furthermore, any non-compliance with applicable laws or regulations could have a material adverse effect on the Corporation's operations.

Risk Management and Risks (continued)

Regulatory & Compliance Risk (continued)

Regulatory Oversight & Government Action

The electricity distribution business in Ontario is regulated, presenting risks to both the financial and operational aspects of the Corporation's rate regulated business. All requests for changes to electricity distribution charges require OEB approval. The Corporation periodically files applications to the OEB for rate adjustments to support the renewal, replacement and growth of its distribution system. Decisions by the OEB to disallow or limit the recovery of costs, or to restrict the ability to earn the allowed ROE could materially and adversely affect the Corporation's distribution revenue. There is no assurance that OEB decisions will permit the Corporation to recover all costs incurred or to earn the ROE necessary for financial sustainability.

As a municipally owned LDC, the Corporation is also subject to actions by all three levels of government and to changes in the broader political environment. Legislation, regulations, or policies enacted by governments may adversely affect the Corporation's financial condition and hinder its ability to pursue strategic and business objectives. Such actions and related uncertainties may result in additional costs for LDCs.

The Corporation actively participates in stakeholder groups, industry associations, and government advocacy that are designed to help inform the development of the legislative and regulatory environment. In addition, the Corporation employs a comprehensive regulatory application process to ensure that rate submissions to the OEB are evidence-based and accurately reflect its business and operational needs.

Compliance with Laws and Regulations

The Corporation must comply with all applicable laws and regulations as well as other requirements to which it subscribes or is subject to. These requirements may arise from Federal, Provincial, or Municipal statutes, regulations, by-laws, or other legal instruments. In addition, the Corporation must adhere to specific industry requirements, such as the IESO Market Rules, OEB license terms and conditions, and other relevant industry codes. Failure to comply with applicable laws, regulations, or requirements could have a material adverse effect on the Corporation.

The Corporation actively monitors its business activities that could be subject to potential compliance actions, including monitoring of applicable legislation and regulations for changes, as well as implementing appropriate measures in response.

Strategic Risk

The Corporation pursues growth through mergers and acquisitions as well as organically through development projects and capital expenditures. The Corporation's business model and strategic direction are based on several key assumptions, including the anticipated growth of its business mix, electricity demand forecasts that reflect broader economic growth projections, the evolution of technology used in the industry, Ontario's electricity regulatory model and broader energy policy developments. Any significant changes to these underlying assumptions may require the Corporation to reevaluate its business model and strategic direction. The Corporation monitors industry trends and the broader business environment, as well as conducts customer outreach to better understand the evolving needs and expectations of its customers.

Risk Management and Risks (continued)

Regulatory & Compliance Risk (continued)

Financial Risk

The Corporation is exposed to changes in economic conditions and risks related to the financial markets, which may adversely affect its financial performance.

Economic Conditions

Changes in interest rates, inflation, government policies, employment levels, business investments, technological developments and other factors may influence energy consumption demand. In addition, an economic downturn could impair customers' ability to pay their bills in a timely manner. These changes could impact the Corporation's operations and cash flows. The regulatory framework partially mitigates the impact of market fluctuations through its rate-setting process by providing the Corporation with the opportunity to earn a regulated return on equity from its electricity distribution business.

Credit Risk

Credit risk is the risk that one party to a financial instrument will fail to discharge an obligation and cause the other party to incur a financial loss. Under Provincial regulation, electricity distribution companies in Ontario are required to act as the billing agent for all industry participants, and must remit billed amounts accruing to these participants irrespective of whether such amounts are ultimately collected. This requirement exposes the Corporation to credit risk, primarily through its customer receivables. The Corporation has implemented credit and collection policies that comply with OEB regulation to mitigate the exposure to credit risk.

Risks Associated with Arranging Debt Financing

The Corporation relies on debt financing to repay existing indebtedness and to finance its ongoing business operations. The Corporation's ability to arrange sufficient and cost-effective debt financing could be adversely affected by factors such as financial market conditions (such as changes in interest rates), the regulatory environment in Ontario, the Corporation's operating results and financial condition, ratings assigned to the Corporation and its debt securities by credit rating agencies, the timing of debt maturities, and other general economic conditions.

Downgrades to the Corporation's credit ratings may negatively impact the Corporation's ability to access debt capital on favourable terms and increase the Corporation's cost of debt. The inability to access debt capital markets within a desired timeframe could impair the Corporation's ability to fund capital expenditures and meet other financial obligations, which could adversely affect future operating results and financial position. Further, the need to raise additional capital could occur if existing financing arrangements are insufficient to support the Corporation's regulated electricity distribution and other businesses.

Risk Management and Risks (continued)

Economic Conditions (continued)

Interest Rate and Currency Exchange Risk

The Corporation is exposed to short-term interest rate risk associated with its short-term debt under the credit facility and Commercial Paper Program. Additionally, fluctuations in interest rates impact the valuation of the Corporation's post-employment benefit obligations. The Corporation manages interest rate risk by monitoring its fixed and floating rate instruments and taking necessary actions to maintain an appropriate balance.

The Corporation's exposure to currency exchange risk is limited, arising primarily from U.S. dollar-denominated cash and investment security balances. Fluctuations in currency exchange rates are not expected to have a material impact on the Corporation's operations or financial condition.

Operational Risk

Grid Operations and Project Execution Risk

The Corporation's ability to safely and reliably distribute electricity depends on its grid infrastructure. Failure to plan, build and maintain the electricity distribution system, including optimizing system capacity, renewing deteriorating infrastructure, and hardening the grid, could disrupt the Corporation's ability to provide safe and reliable service to its customers. The Corporation has asset management and investment plans in place focusing on asset renewal, grid expansion, and grid resiliency. The Corporation also has emergency response and business continuity processes to enable efficient deployment and coordination of resources to mitigate the effects of grid-related emergencies.

The Corporation is a capital-intensive business and the failure to effectively manage projects on time and on budget could adversely affect the Corporation's financial performance. Projects are subject to risks of delay and cost overruns from factors including material and labour costs, tariffs or trade restrictions, legislative or regulatory changes, weather conditions, and supplier non-performance. The Corporation continues to ensure expenditures are reasonable and prudent and manages project execution with its robust project planning and governance processes.

Health & Safety Risk

The Corporation is engaged in the construction, operation, and maintenance of high voltage electrical infrastructure throughout the communities it serves and is exposed to significant safety hazards inherent in this work. Damage to utility infrastructure, whether resulting from natural or human-caused hazards, could pose risks to public and employee safety. The Corporation is also subject to government legislation and regulations relating to health and safety. Failure to comply with these requirements or to keep the public and employees safe, could result in adverse operational, financial, compliance and reputational impact on the Corporation.

The Corporation's safety management program is based on the principle of continuous improvement and incorporates measures such as equipment inspections, employee training and ongoing education, and safety audits. The Corporation has undertaken initiatives to promote psychological safety and provide additional support through the employee assistance program. In addition, the Corporation is prepared to respond to potential infectious disease emergencies, with the objective of limiting health and safety exposures for both the public and employees.

Risk Management and Risks (continued)

Operational Risk (continued)

Technological and Cybersecurity Risk

The Corporation's ability to operate effectively in the Ontario electricity market depends in part on the management of its information technology and operational technology systems. These systems are essential for operating and monitoring an electricity distribution network, as well as supporting financial, billing, and other business functions. As a critical infrastructure operator, the Corporation's distribution infrastructure and technology systems are vulnerable to damage or interruption resulting from cyberattacks, breaches or other forms of compromise. Systems and technologies that may be outdated could be incompatible with modern security features, further increasing vulnerability to disruption.

A cybersecurity incident could lead to service disruptions, theft of intellectual property, and unauthorized access to confidential customer or business information, resulting in regulatory scrutiny, litigation, and reputational harm. The ongoing evolution of technology, including increased digitization as well as the adoption of emerging technologies such as artificial intelligence, continues to intensify the cybersecurity threat environment, with attacks becoming more sophisticated, frequent, and severe.

The Corporation maintains cyber insurance and has established a cybersecurity program that incorporates industry leading practices. This program includes employee training, asset protection and safeguarding of sensitive information, continuous monitoring of technology systems, and incident response procedures designed to minimize the impact of cyberattacks, breaches or other compromises. The Corporation continues to make proactive investments to strengthen the distribution system, including addressing cybersecurity threats.

Supply Chain Risk

Global supply chains have been disrupted by several factors including macroeconomic conditions, the geopolitical environment and trade policies, and labour market constraints. These factors have led to increased material and equipment lead times as well as costs. Prices for key materials and equipment continue to fluctuate as global economic conditions remain uncertain, influenced by volatility in commodity prices, inflation, and interest rates. The Corporation's ability to operate effectively depends in part on timely access to equipment, materials, and key suppliers. Loss of key suppliers or increased volatility in material and equipment lead times could adversely impact the Corporation's operations, as well as its capital project planning and execution. The Corporation continues to diversify its supplier base to reduce reliance on single sources and advances procurement of key equipment and materials that are expected to have long lead times.

Human Resources and Labour Relations Risk

The Corporation's workforce consists of both unionized and non-unionized employees, encompassing a broad range of skills in trades, technical, and professional disciplines within a competitive labour market. There is a risk that the Corporation may not always be able to attract or retain the skilled and experienced personnel required to support its business objectives and execute its strategy. The Corporation implements a variety of programs focused on talent attraction, development, and retention, including succession planning and knowledge retention initiatives, to ensure the workforce remains capable of meeting the evolving needs of the business.

Risk Management and Risks (continued)

Operational Risk (continued)

Human Resources and Labour Relations Risk (continued)

The Corporation is committed to fostering effective relationships with its union, which is represented by the PWU and IBEW. Agreements have been reached with the PWU for the period from June 1, 2025, to May 31, 2028, and with the IBEW for the period from April 1, 2024, to March 31, 2027. Inability to negotiate collective agreements with the PWU and IBEW on mutually acceptable terms could result in work disruptions, which may adversely affect the Corporation's business, including its ability to maintain the continued supply of electricity to customers.

Climate Change and Environmental Risk

The Corporation's service territory, its energy-related infrastructure and other facilities are exposed to risks associated with climate change and extreme weather events. Increasing frequency and intensity of events such as extreme winds, flash floods, and severe thunderstorms have the potential to cause physical damage to the Corporation's distribution infrastructure and facilities, resulting in service disruptions and higher repair and replacement costs.

The Corporation invests in capital projects and monitors the condition of its assets to manage the risk of equipment failures and to determine the need for as well as timing of replacement of its distribution infrastructure. Further, the Corporation continues to adapt and increase its infrastructure and operations resilience and reliability to address the effects of climate change and extreme weather events. These initiatives include updating major equipment specifications, revising design practices, improving planning processes, strengthening maintenance programs, building supply chain resiliency, and implementing emergency preparedness programs to minimize the impact of disruptions.

The Corporation is subject to Canadian environmental laws and regulations. The release of hazardous or other harmful substances such as asset leaks and spills may result in adverse environmental impacts and could lead to governmental orders requiring the Corporation's investigation, control and remediation. Failure to comply could subject the Corporation to injunction, fines, or other penalties.

The Corporation continues to place insurance coverage where available to mitigate the risks associated with damage to assets or service disruption. Standardized response procedure is in place to ensure timely inspection, investigation, remediation, and reporting of asset leaks and spills upon discovery. The Corporation also monitors Canadian and Ontario regulations regarding GHG emissions and continues to track and voluntarily disclose Alectra Utilities' GHG emissions to the public.

Attachment 1-15

2025 Reconciliation between Audited & OEB Financial Statements

Please see live Excel version

Attachment 9-1

DVA Continuity Schedule HRZ

Please see live Excel version

Attachment 9-2

DVA Continuity Schedule BRZ

Please see live Excel version

Attachment 9-3

DVA Continuity Schedule PRZ

Please see live Excel version

Attachment 9-4

DVA Continuity Schedule ERZ

Please see live Excel version

Attachment 9-5

DVA Continuity Schedule GRZ

Please see live Excel version

1.1. GROUP 1 DVA PROPOSED FOR DISPOSITION

Alectra Utilities has updated this section of the schedule. The amounts proposed for disposition are aligned with the audited financial statements for the fiscal year ended December 31, 2025.

In the 2026 EDR Application Decision, the OEB approved the disposition of the Group 1 accounts balances as of December 31, 2024 on a final basis for the Horizon Utilities, Brampton, PowerStream, Enersource and Guelph Hydro RZs.

In this filing, Alectra Utilities requests disposition of Group 1 account balances for all rate zones as of December 31, 2025, including interest projected to December 31, 2026 on a final basis. Alectra Utilities provides the relief sought for its Group 1 deferral and variance account balances by rate zone, below.

1.1.1. Horizon Utilities RZ

The Group 1 balances as of December 31, 2025, in the amount of $(15,350,660) have been adjusted for the following items to determine the amount for disposition of $(17,660,210) as identified in Table 9-3-66, below:

- Group 1 balances approved for disposition in the 2026 Annual Filing have been excluded;
- Principal adjustments which are not included in the audited financial statements have been identified separately as an adjustment to the balance requested for disposition. Consequently, the account balances on Tab 2a. DVA Continuity Schedule differ from the annual RRR filing;
- Projected carrying charges for each Group 1 Account balance to the proposed rate rider implementation date are included (i.e., the amount for disposition includes projected carrying charges to December 31, 2026); and
- Only eligible residual balances in Account 1595, for which rate riders have expired, are included. The disposition of these balances is requested two years after expiration.

Table 9-3-66: Group 1 Balances for Disposition – Horizon Utilities RZ

Description	Amount
Group 1 Account Balances as of December 31, 2025	**(15,350,660)**
Subtract 2026 Annual Filing Disposition (EB-2025-0055) - Recovery from Customers	6,126,623
Add Principal Adjustments	4,984,879
Add Projected Carrying Charges	(473,993)
Deduct 1595 Residual Balances to be disposed in a future rate proceeding	693,813
Adjusted Group 1 Account Balances for Disposition - Repayment to Customers	**(17,660,210)**

Alectra Utilities has computed the disposition threshold for the Horizon Utilities RZ, based on the adjusted Group 1 balances to be $-0.0033/kWh, as identified in Table 9-3-67, below.

Table 9-3-67: Calculation of Disposition Threshold – Horizon Utilities RZ

Description	Account	Amount
Low Voltage	1550	(339,809)
Smart Meter Entity Charge	1551	(329,244)
RSVA - Wholesale Market Service Charge excluding CBR	1580	(9,543,830)
RSVA - Wholesale Market Service Charge - Capacity Based Recovery ("CBR") Class B	1580	3,350,466
RSVA - Retail Transmission Network Charge	1584	1,834,947
RSVA - Retail Transmission Connection Charge	1586	(1,612,619)
RSVA - Power	1588	(9,590,926)
RSVA - Global Adjustment	1589	(893,031)
Disposition and Recovery/Refund of Regulatory Balances	1595	1,773,386
Group 1 Account Balances as of December 31, 2025		**(15,350,660)**
Subtract 2026 Annual Filing Disposition (EB-2025-0055) - Recovery from Customers		6,126,623
Add Principal Adjustments		4,984,879
Add Projected Carrying Charges		(473,993)
Deduct 1595 Residual Balances to be disposed in a future rate proceeding		693,813
Adjusted Group 1 Account Balances for Disposition - Repayment to Customers		**(17,660,210)**
2027 kWhs		5,367,511,954
Threshold Test $/kWh		**-0.0033**

Alectra Utilities has completed and filed the DVA Continuity Schedule as Attachment 9-1 for the Horizon Utilities RZ. Alectra Utilities has reconciled the Group 1 balances in the 2025 RRR, section 2.1.7 for the Horizon Utilities RZ. The variance to the RRR balance is equal to the principal adjustments made in the current disposition period. A reconciliation of the balance requested for disposition is provided in Table 9-3-68, below. Alectra Utilities confirms that the last OEB-approved balance of $6,126,623 for the Horizon Utilities RZ has been transferred to Account 1595, and that residual balances in Account 1595 Sub-accounts for each vintage year have only been disposed once. Further, Alectra Utilities has confirmed that the proposed load forecast for 2027 is used for the billing determinants to calculate the rater riders.

Alectra Utilities relied upon the OEB's prescribed interest rates to calculate carrying charges on the deferral and variance account balances. The prescribed interest rates of 2.55% for Q1 2026, was used to calculate forecasted interest for 2026. No adjustments have been made to any deferral and variance account balances previously approved by the OEB on a final basis.

Table 9-3-68: Deferral and Variance Account Reconciliation – Horizon Utilities RZ

Account Description	Account	Principal Amounts as of Dec 31, 2025	Carrying Charges to Dec 31, 2025	Principal Disposition during 2026	Interest Disposition during 2026	Projected Carrying Charges to Dec 31, 2025	Total Disposition before Principal Adjustment	Principal Adjustment	Projected Carrying Charges to December 31, 2025	1595 Balances Not Claimed in 2026	Total Disposition
Group 1 Accounts:											
Low Voltage	1550	(338,681)	(1,128)	(42,811)	(2,463)	(9,728)	(394,811)				(394,811)
Smart Meter Entity Charge	1551	(313,165)	(16,079)	206,834	13,468	(2,711)	(111,653)				(111,653)
RSVA - Wholesale Market Service Charge excluding CBR	1580	(9,496,680)	(47,150)	1,725,872	30,219	(198,156)	(7,985,896)				(7,985,896)
RSVA - Wholesale Market Service Charge - CBR B	1580	3,280,592	69,874	(1,568,455)	(56,070)	43,659	1,769,600				1,769,600
RSVA - Retail Transmission Network Charge	1584	1,722,854	112,093	(1,738,481)	(106,908)	(398)	(10,840)				(10,840)
RSVA - Retail Transmission Connection Charge	1586	(1,601,159)	(11,460)	500,860	7,485	(28,058)	(1,132,331)				(1,132,331)
RSVA - Power	1588	(9,441,819)	(149,107)	802,113	96,916	(220,313)	(8,912,211)	6,532,897	166,589		(2,212,724)
Sub-total not including RSVA Power Global Adjustment		**(16,188,058)**	**(42,957)**	**(114,069)**	**(17,353)**	**(415,704)**	**(16,778,142)**	**6,532,897**	**166,589**		**(10,078,655)**
RSVA - Power Global Adjustment	1589	(1,041,164)	148,133	(5,228,015)	(277,504)	(159,864)	(6,558,414)	(1,548,019)	(39,474)		(8,145,907)
		—	—	—	—	—	—	—	—		
Total including RSVA Power Global Adjustment		**(17,229,222)**	**105,176**	**(5,342,084)**	**(294,857)**	**(575,568)**	**(23,336,556)**	**4,984,879**	**127,114**		**(18,224,562)**
Disposition and Recovery/Refund of Regulatory Balances (2018)	1595	—	—	—	—	—	—			—	—
Disposition and Recovery/Refund of Regulatory Balances (2019)	1595	—	—	—	—	—	—			—	—
Disposition and Recovery/Refund of Regulatory Balances (2020)	1595	—	—	—	—	—	—			—	—
Disposition and Recovery/Refund of Regulatory Balances (2021)	1595	—	—	—	—	—	—			—	—
Disposition and Recovery/Refund of Regulatory Balances (2022)	1595	493,686	(4,036)	(493,718)	4,036	—	(32)			(32)	—
Disposition and Recovery/Refund of Regulatory Balances (2023)	1595	230,791	327,676	—	—	5,885	564,352			—	564,352
Disposition and Recovery/Refund of Regulatory Balances (2024)	1595	(921,647)	1,637,622	—	—	(23,502)	692,473			692,473	—
Disposition and Recovery/Refund of Regulatory Balances (2025)	1595	(310,672)	319,965	—	—	(7,922)	1,372			1,372	—
Total 1595		**(507,842)**	**2,281,228**	**(493,718)**	**4,036**	**(25,539)**	**1,258,165**	**—**	**—**	**693,813**	**564,352**
Total Amount for Disposition		**(17,737,064)**	**2,386,404**	**(5,835,802)**	**(290,821)**	**(601,107)**	**(22,078,391)**	**4,984,879**	**127,114**	**693,813**	**(17,660,210)**

Alectra Utilities is seeking a one-year disposition period for the Group 1 balances for the Horizon Utilities RZ. This approach is consistent with the EDDVAR Report which states on page 6 that "the default disposition period used to clear the account balances through a rate rider should be one year".

Wholesale Market Participants ("WMPs")

WMPs participate directly in the IESO administered market and settle commodity and market-related charges directly with the IESO. Alectra Utilities has established separate rate riders to dispose of the balances in the RSVAs for WMPs. The balances in Account 1588 RSVA – Power, Account 1580 RSVA – Wholesale Market Service Charge (including CBR) and Account 1589 RSVA – Global Adjustment have not been allocated to WMPs.

Global Adjustment ("GA") and Capacity Based Response ("CBR") Disposition

Alectra Utilities has also established separate rate riders to dispose of the GA and CBR account balances for the Horizon Utilities RZ. The GA rate rider is only applicable to non-RPP customers, and the CBR rate rider is only applicable to Class B customers. Alectra Utilities' Class A customers are invoiced actual GA and CBR, therefore, none of the variance in the GA and CBR account balance is attributed to these customers.

There were 8 Alectra Utilities customers in the Horizon Utilities RZ that transitioned between Class A and Class B during 2025, under the IESO's Industrial Conservation Initiative ("ICI"). These transition customers paid GA and CBR during the period they were Class B customers. As such, these customers will only be allocated the portion of the GA and CBR account balance which accrued to them as a Class B customer.

These GA and CBR amounts will be settled through twelve equal adjustments to bills.These customers will not be charged or refunded the general GA and CBR rate riders.

Table 9-3-69 below identifies the GA and CBR balances disposed of through rate riders and specific bill adjustments.

Alectra Utilities requests disposition of its total GA balance of $(8,145,907), of which $(8,020,951) will be disposed of through a rate rider; and $(124,956) will be disposed of through specific bill adjustment, as discussed above. Alectra Utilities requests disposition of its total CBR balance of $1,769,600, of which $1,761,222 will be disposed of through a rate rider; and $8,378 will be disposed of through specific bill adjustments, as discussed above. Tab "6.1a GA Allocation" and "6.2a CBR B Allocation" in the DVA Continuity Schedule present the detailed calculation of the bill adjustments.

Table 9-3-69: Disposition of GA Balances – Horizon Utilities RZ

Description	Amount
Global Adjustment - Non-RPP Class B Customers	(8,020,951)
Global Adjustment - Transition Customers	(124,956)
Class B Non-RPP Customers only - GA Rate Rider/Bill Adjustment	**(8,145,907)**
Capacity Based Recovery - Non-RPP Class B Customers	1,761,222
Capacity Based Recovery - Transition Customers	8,378
Class B Non-RPP Customers only - CBR Rate Rider/Bill Adjustment	**1,769,600**

A summary of the rate riders applicable to each group of customers is presented in Table 9-3-70 below.

Table 9-3-70: Rate Riders by Customer Group – Horizon Utilities RZ

Customers	DVA Rate Rider 1 [1]	DVA Rate Rider 2 [2]	CBR B Rate Rider [3] (if applicable)	GA Rate Rider	Specific Bill Adjustment
WMPs	x				
Class A (Full Year)	x	x			
Transition Customers	x	x			x
Class B non-RPP Customers (Full Year)	x	x	x	x	
Class B RPP Customers	x	x	x		
1. DVA Rate Rider 1 = disposition of low voltage, SME, Network, Connection, IRM balances					
2. DVA Rate Rider 2 = disposition of Power and Wholesale Market Service Charges (excluding CBR)					
3. If the allocated CBR B amount does not produce a rate rider in one or more rate class, the entire balance is transferred into Account 1580 WMS control account					

WMPs are charged DVA Rate Rider 1 only, which includes account balances for low voltage charges, retail transmission network charges, and retail transmission connection charges.

Class A customers are charged the sum of DVA Rate Rider 1 and DVA Rate Rider 2, the latter of which includes account balances for power and wholesale market service charges excluding CBR.

Transition customers are charged the sum of DVA Rate Rider 1 and DVA Rate Rider 2; and a customer-specific bill adjustment for their portion of the GA and CBR account balances.

Class B, non-RPP customers are charged the sum of DVA Rate Riders 1 and 2; and the GA and CBR Rate Riders.

Class B RPP customers are charged the sum of DVA Rate Riders 1 and 2; and the CBR Rate Rider.

The Group 1 DVAs disposition by customer group is identified in Table 9-3-71, below.

Table 9-3-71: Group 1 DVAs Disposition by Customer Group – Horizon Utilities RZ

Description	Account	Amount
Low Voltage	1550	(394,811)
Smart Meter Entity Charge (Residential and GS<50kW Classes Only)	1551	(111,653)
Retail Transmission Network Charge	1584	(10,840)
Retail Transmission Connection Charge	1586	(1,132,331)
Disposition and Recovery/Refund of Regulatory Balances	1595	564,352
All Customers - DVA Rate Rider 1		**(1,085,283)**
Power	1588	(2,212,724)
Wholesale Market Service Charge excluding CBR	1580	(7,985,896)
All Customers ex WMPs - DVA Rate Rider 2		**(10,198,620)**
Wholesale Market Service Charge - CBR Class B	1580	1,761,222
Capacity Based Recovery - Transition Customers	1580	8,378
All Class B Customers ex WMPs - CBR B Rate Rider/Bill Adjustment		**1,769,600**
Global Adjustment - Non-RPP Class B Customers	1589	(8,020,951)
Global Adjustment - Transition Customers	1589	(124,956)
Class B Non-RPP Customers only - GA Rate Rider/Bill Adjustment		**(8,145,907)**
Total (Repayment to)/Recovery from Customers		**(17,660,210)**
Disposition via Rate Rider		(17,543,632)
Global Adjustment - Transition Customers		(124,956)
Capacity Based Recovery - Transition Customers		8,378

All balances claimed are allocated to the rate classes based on the default cost allocation methodology, as identified in the EDDVAR report.

The billing determinants, billing adjustments, and calculation of the rate riders are provided in Tabs 4 and 7 in the DVA Continuity Schedule filed as Attachment 9-1. Alectra Utilities requests disposition of the Horizon Utilities RZ adjusted Group 1 balances, through the rate riders identified in Table 9-3-72, below.

Table 9-3-72: Deferral and Variance Account Riders – Horizon Utilities RZ

Customer Class	Deferral/ Variance Account Rate Rider		Deferral/ Variance Account Rate Rider for Non-WMP		Global Adjustment Rate Rider Non-RPP Class B		CBR B Rate Rider Class B Consumer	
	$/kWh	$/kW	$/kWh	$/kW	$/kWh	$/kW	$/kWh	$/kW
Residential	(0.0024)				(0.0071)		0.0005	
General Service Less Than 50 kW	(0.0024)				(0.0071)		0.0005	
General Service 50 To 4,999 kW		(0.0622)		(0.7552)	(0.0071)			0.1605
Large Use		(1.0080)						
Large Use With Dedicated Assets		(0.0904)		(0.8285)				
Unmetered Scattered Load	(0.0023)				(0.0071)		0.0005	
Street Lighting		(0.8389)			(0.0071)			0.1730
Sentinel Lighting		(0.8469)			(0.0071)			0.1731

Commodity Accounts Analysis Workform

The Commodity Accounts Analysis Workform for the Horizon Utilities RZ is filed as Attachment 9-17. The Commodity Accounts Analysis Workform assesses the reasonability of Account 1589, RSVA GA and Account 1588, RSVA Power through a calculation of expected principal balances and compares the expected amounts to the amounts reported in the distributor's general ledger. The Commodity Accounts Analysis Workform provides a tool to assess if the principal activity in Accounts 1589 and 1588 for a specific year is reasonable and distributors must explain unreconciled variances greater than +/- 1% of IESO purchases. Distributors are required to submit a Commodity Accounts Analysis Workform for each year that has not previously been approved by the OEB for disposition.

Account 1589

The Commodity Accounts Analysis Workform compares the principal activity in the general ledger for Account 1589 to the expected principal balances based on monthly GA volumes, revenue, and costs.

The principal activity in Account 1589 recorded in 2025 was $(6,269,179) as identified in Table 9-3-73 below. The principal activity balance, after known adjustments of $(1,559,588) was $(7,828,767). This is compared to the expected principal balance in Account 1589 of $(7,422,545) calculated in Attachment 9-17, which results in an unreconciled difference of $(406,222). This represents 0.77% of Alectra Utilities 2025 IESO purchases in the Horizon Utilities RZ, which is within the OEB's threshold (+/- 1% of IESO purchases).

Table 9-3-73: Commodity Accounts Analysis Workform Summary

Description	Amount
Principal Activity in RSVA(GA)	(6,269,179)
Add Known Adjustments	(1,559,588)
Adjusted Principal Activity in RSVA(GA)	(7,828,767)
Expected Principal Activity in RSVA(GA)	(7,422,545)
Variance $	(406,222)
Total 2025 IESO Purchases	52,417,586
Absolute Variance as a % of IESO Purchases	**0.77 %**

Account 1588

The Commodity Accounts Analysis Workform also includes a reasonability test for Account 1588, RSVA Power, and compares the annual Account 1588 variance to the Cost of Power purchases in the respective year.

The transactions in Account 1588 recorded in 2025 was $(8,639,707) as identified in Table 9-3-74 below. The transactions, after principal adjustments of $6,532,897 was $(2,106,809). This is compared to the power purchased of $404,748,827, which represents 0.52% of purchases, which is within the OEB's threshold.

Table 9-3-74: Account 1588 Power Summary

Description	Amount
Principal Activity in RSVA(Power)	(8,639,707)
Add Known Adjustments	6,532,897
Total Activity in 2025	(2,106,809)
Account 4705 - Power Purchased	404,748,827
Absolute Variance as a % of Power Purchased	**0.52 %**

1.1.2. Brampton RZ

The Group 1 balances as of December 31, 2025, in the amount of $(6,704,287) have been adjusted for the following items to determine the amount for disposition of $(12,297,633) as identified in Table 9-3-75, below:

- Group 1 balances approved for disposition in the 2026 Annual Filing have been excluded;
- Principal adjustments which are not included in the audited financial statements have been identified separately as an adjustment to the balance requested for disposition. Consequently, the account balances on Tab 2a. DVA Continuity Schedule differ from the annual RRR filing;
- Projected carrying charges for each Group 1 Account balance to the proposed rate rider implementation date are included (i.e., the amount for disposition includes projected carrying charges to December 31, 2026); and
- Only eligible residual balances in Account 1595, for which rate riders have expired, are included. The disposition of these balances is requested two years after expiration.

Table 9-3-75: Group 1 Balances for Disposition – Brampton RZ

Description	Amount
Group 1 Account Balances as of December 31, 2025	**(6,704,287)**
Subtract 2026 Annual Filing Disposition (EB-2025-0055) - Recovery from Customers	2,546,542
Add Principal Adjustments	(1,323,805)
Add Projected Carrying Charges	(328,679)
Deduct 1595 Residual Balances to be disposed in a future rate proceeding	1,394,320
Adjusted Group 1 Account Balances for Disposition - Repayment Customers	**(12,297,633)**

Alectra Utilities has computed the disposition threshold for the Brampton RZ, based on the adjusted Group 1 balances to be $-0.0029/kWh, as identified in Table 9-3-76, below.

Table 9-3-76: Calculation of Disposition Threshold – Brampton RZ

Description	Account	Amount
Low Voltage	1550	(379,824)
Smart Meter Entity Charge	1551	(223,535)
RSVA - Wholesale Market Service Charge excluding CBR	1580	(7,976,187)
RSVA - Wholesale Market Service Charge - Capacity Based Recovery ("CBR") Class B	1580	3,290,852
RSVA - Retail Transmission Network Charge	1584	1,277,567
RSVA - Retail Transmission Connection Charge	1586	(1,706,797)
RSVA - Power	1588	(703,363)
RSVA - Global Adjustment	1589	(2,067,167)
Disposition and Recovery/Refund of Regulatory Balances	1595	1,784,166
Group 1 Account Balances as of December 31, 2025		**(6,704,287)**
Subtract 2026 Annual Filing Disposition (EB-2025-0055) - Recovery from Customers		2,546,542
Add Principal Adjustments		(1,323,805)
Add Projected Carrying Charges		(328,679)
Deduct 1595 Residual Balances to be disposed in a future rate		1,394,320
Adjusted Group 1 Account Balances for Disposition - Repayment to Customers		**(12,297,633)**
2027 kWhs		4,294,092,348
Threshold Test $/kWh		**-0.0029**

Alectra Utilities has completed and filed the DVA Continuity Schedule as Attachment 9-2 for the Brampton RZ. Alectra Utilities has reconciled the Group 1 balances in the 2025 RRR, section 2.1.7 for the Brampton RZ. The variance to the RRR balance is equal to the principal adjustments made in the current disposition period. A reconciliation of the balance requested for disposition is provided in Table 9-3-77, below. Alectra Utilities confirms that the last OEB-approved balance of $2,546,542 for the Brampton RZ has been transferred to Account 1595, and that residual balances in Account 1595 Sub-accounts for each vintage year have only been disposed once. Further, Alectra Utilities has confirmed that the proposed load forecast for 2027 is used for the billing determinants to calculate the rater riders.

Alectra Utilities relied upon the OEB's prescribed interest rates to calculate carrying charges on the deferral and variance account balances. The prescribed interest rates of 2.55% for Q1 2026 was used to calculate forecasted interest for 2026. No adjustments have been made to any deferral and variance account balances previously approved by the OEB on a final basis.

Table 9-3-77: Deferral and Variance Account Reconciliation – Brampton RZ

Account Description	Account	Principal Amounts as of Dec 31, 2025	Carrying Charges to Dec 31, 2025	Principal Disposition during 2026	Interest Disposition during 2026	Projected Carrying Charges to Dec 31, 2026	Total Disposition before Principal Adjustment	Principal Adjustment	Projected Carrying Charges to December 31, 2026	1595 Balances Not Claimed in 2026	Total Disposition
Group 1 Accounts:											
Low Voltage	1550	(372,093)	(7,731)	170,816	6,190	(5,133)	(207,950)				(207,950)
Smart Meter Entity Charge	1551	(212,642)	(10,893)	140,629	9,141	(1,836)	(75,601)				(75,601)
RSVA - Wholesale Market Service Charge excluding CBR	1580	(7,954,513)	(21,674)	1,305,594	12,108	(169,547)	(6,828,031)				(6,828,031)
RSVA - Wholesale Market Service Charge - CBR B	1580	3,220,260	70,592	(1,498,818)	(55,331)	43,897	1,780,600				1,780,600
RSVA - Retail Transmission Network Charge	1584	1,207,208	70,359	(1,101,279)	(61,066)	2,701	117,923				117,923
RSVA - Retail Transmission Connection Charge	1586	(1,671,607)	(35,190)	722,347	30,448	(24,206)	(978,208)				(978,208)
RSVA - Power	1588	(680,437)	(22,926)	1,639,207	50,629	24,449	1,010,922	666,633	16,999		1,694,555
Sub-total not including RSVA Power Global Adjustment		**(6,463,823)**	**42,538**	**1,378,496**	**(7,880)**	**(129,676)**	**(5,180,345)**	**666,633**	**16,999**	**—**	**(4,496,712)**
RSVA - Power Global Adjustment	1589	(2,083,913)	16,746	(3,791,139)	(153,223)	(149,814)	(6,161,344)	(1,990,438)	(50,756)		(8,202,538)
Total including RSVA Power Global Adjustment		**(8,547,736)**	**59,283**	**(2,412,643)**	**(161,103)**	**(279,490)**	**(11,341,688)**	**(1,323,805)**	**(33,757)**	**—**	**(12,699,250)**
Disposition and Recovery/Refund of Regulatory Balances (2018)	1595										
Disposition and Recovery/Refund of Regulatory Balances (2019)	1595										
Disposition and Recovery/Refund of Regulatory Balances (2020)	1595										
Disposition and Recovery/Refund of Regulatory Balances (2021)	1595										
Disposition and Recovery/Refund of Regulatory Balances (2022)	1595	(41,238)	14,085	41,288	(14,084)	1	52			52	—
Disposition and Recovery/Refund of Regulatory Balances (2023)	1595	75,463	324,229	—	—	1,924	401,617			—	401,617
Disposition and Recovery/Refund of Regulatory Balances (2024)	1595	323,441	1,544,143	—	—	8,248	1,875,831			1,875,831	—
Disposition and Recovery/Refund of Regulatory Balances (2025)	1595	(1,004,148)	548,192	—	—	(25,606)	(481,562)			(481,562)	—
Total 1595		**(646,483)**	**2,430,649**	**41,288**	**(14,084)**	**(15,432)**	**1,795,938**	**—**	**—**	**1,394,320**	**401,617**
Total Amount for Disposition		**(9,194,219)**	**2,489,932**	**(2,371,355)**	**(175,187)**	**(294,922)**	**(9,545,751)**	**(1,323,805)**	**(33,757)**	**1,394,320**	**(12,297,633)**

Alectra Utilities is seeking a one-year disposition period for the Group 1 balances for the Brampton RZ. This approach is consistent with the EDDVAR Report which states on page 6 that "the default disposition period used to clear the account balances through a rate rider should be one year".

Wholesale Market Participants ("WMPs")

WMPs participate directly in the IESO administered market and settle commodity and market-related charges directly with the IESO. Alectra Utilities has established separate rate riders to dispose of the balances in the RSVAs for WMPs. The balances in Account 1588 RSVA – Power, Account 1580 RSVA – Wholesale Market Service Charge (including CBR) and Account 1589 RSVA – Global Adjustment have not been allocated to WMPs.

Global Adjustment and Capacity Based Response Disposition

Alectra Utilities has also established separate rate riders to dispose of the GA and CBR account balances for the Brampton RZ. The GA rate rider is only applicable to non-RPP customers, and the CBR rate rider is only applicable to Class B customers. Alectra Utilities' Class A customers are invoiced actual GA and CBR, therefore, none of the variance in the GA and CBR account balance is attributed to these customers.

There were 13 Alectra Utilities customers in the Brampton RZ that transitioned between Class A and Class B during 2025 under the IESO's Industrial Conservation Initiative ("ICI"). These transition customers paid GA and CBR during the period they were Class B customers. As such, these customers will only be allocated the portion of the GA and CBR account balance which accrued to them as a Class B customer.

These GA and CBR amounts will be settled through twelve equal adjustments to bills. These customers will not be charged or refunded the general GA and CBR rate riders.

Table 9-3-78 below identifies the GA and CBR balances disposed of through rate riders and specific bill adjustments.

Alectra Utilities requests disposition of its total GA balance of $(8,202,538) of which $(8,044,663) will be disposed of via rate rider; and $(157,875) will be disposed of via specific bill adjustments, as discussed above. Alectra Utilities requests disposition of its total CBR balance of $1,780,600, of which $1,768,470 will be disposed of via rate rider; and $12,130 will be disposed of via specific bill adjustments, as discussed above. Tab “6.1a GA Allocation” and “6.2a CBR B Allocation” in the DVA Continuity Schedule present the detailed calculation of the bill adjustments.

Table 9-3-78: Disposition of GA Balances – Brampton RZ

Description	Amount
Global Adjustment - Non-RPP Class B Customers	(8,044,663)
Global Adjustment - Transition Customers	(157,875)
Class B Non-RPP Customers only - GA Rate Rider/Bill Adjustment	**(8,202,538)**
Capacity Based Recovery - Non-RPP Class B Customers	1,768,470
Capacity Based Recovery - Transition Customers	12,130
Class B Non-RPP Customers only - CBR Rate Rider/Bill Adjustment	**1,780,600**

A summary of the rate riders applicable to each group of customers is identified in Table 9-3-79 below.

Table 9-3-79: Rate Riders by Customer Group – Brampton RZ

Customers	DVA Rate Rider 1 [1]	DVA Rate Rider 2 [2]	CBR B Rate Rider [3] (if applicable)	GA Rate Rider	Specific Bill Adjustment
WMPs	x				
Class A (Full Year)	x	x			
Transition Customers	x	x			x
Class B non-RPP Customers (Full Year)	x	x	x	x	
Class B RPP Customers	x	x	x		
1. DVA Rate Rider 1 = disposition of low voltage, SME, Network, Connection, IRM balances					
2. DVA Rate Rider 2 = disposition of Power and Wholesale Market Service Charges (excluding CBR)					
3. If the allocated CBR B amount does not produce a rate rider in one or more rate class, the entire balance is transferred into Account 1580 WMS control account					

WMPs are charged DVA Rate Rider 1 only, which includes account balances for low voltage charges, retail transmission network charges, and retail transmission connection charges.

Class A customers are charged the sum of DVA Rate Rider 1 and DVA Rate Rider 2, the latter of which includes account balances for power and wholesale market service charges excluding CBR.

Transition customers are charged the sum of DVA Rate Rider 1 and DVA Rate Rider 2; and a customer specific bill adjustment for their portion of the GA and CBR account balances.

Class B, non-RPP customers are charged the sum of DVA Rate Riders 1 and 2; and the GA and CBR Rate Rider.

Class B RPP customers are charged the sum of DVA Rate Riders 1 and 2; and the CBR Rate Rider.

The Group 1 DVAs disposition by customer group is identified in Table 9-3-80, below.

Table 9-3-80: Group 1 DVAs Disposition by Customer Group – Brampton RZ

Description	Account	Amount
Low Voltage	1550	(207,950)
Smart Meter Entity Charge (Residential and GS<50kW Classes Only)	1551	(75,601)
Retail Transmission Network Charge	1584	117,923
Retail Transmission Connection Charge	1586	(978,208)
Disposition and Recovery/Refund of Regulatory Balances	1595	401,617
All Customers - DVA Rate Rider 1		**(742,219)**
Power	1588	1,694,555
Wholesale Market Service Charge excluding CBR	1580	(6,828,031)
All Customers ex WMPs - DVA Rate Rider 2		**(5,133,476)**
Wholesale Market Service Charge - CBR Class B	1580	1,768,470
Capacity Based Recovery - Transition Customers	1580	12,130
All Class B Customers ex WMPs - CBR B Rate Rider/Bill Adjustment		**1,780,600**
Global Adjustment - Non-RPP Class B Customers	1589	(8,044,663)
Global Adjustment - Transition Customers	1589	(157,875)
Class B Non-RPP Customers only - GA Rate Rider/Bill Adjustment		**(8,202,538)**
Total (Repayment to)/Recovery from Customers		**(12,297,633)**
Disposition via Rate Rider		(12,151,888)
Global Adjustment - Transition Customers		(157,875)
Capacity Based Recovery - Transition Customers		12,130

All balances claimed are allocated to the rate classes based on the default cost allocation methodology as identified in the EDDVAR report.

The billing determinants, billing adjustments, and calculation of the rate riders are provided in Tabs 4 through 7 in the DVA Continuity Schedule filed as Attachment 9-2. Alectra Utilities requests disposition of the Brampton RZ adjusted Group 1 balances, through the rate riders identified in Table 9-3-81, below.

Table 9-3-81: Deferral and Variance Account Riders – Brampton RZ

Customer Class	Deferral/ Variance Account Rate Rider		Deferral/ Variance Account Rate Rider for Non-WMP		Global Adjustment Rate Rider Non-RPP Class B		CBR B Rate Rider Class B Consumer	
	$/kWh	$/kW	$/kWh	$/kW	$/kWh	$/kW	$/kWh	$/kW
Residential	(0.0014)				(0.0079)		0.0006	
General Service Less Than 50 kW	(0.0014)				(0.0079)		0.0006	
General Service 50 To 699 kW		(0.0552)		(0.4363)	(0.0079)			0.2003
General Service 700 To 4,999 kW		(0.0667)		(0.5253)	(0.0079)			0.1470
Large Use		(0.7197)			(0.0079)			0.2541
Unmetered Scattered Load	(0.0014)				(0.0079)		0.0006	
Street Lighting		(0.4837)			(0.0079)			0.1973

Commodity Accounts Analysis Workform

The Commodity Accounts Analysis Workform for the Brampton RZ is filed as Attachment 9-18. The Commodity Accounts Analysis Workform assesses the reasonability of Account 1589, RSVA GA and Account 1588, RSVA Power through a calculation of expected principal balances and compares the expected amounts to the amounts reported in the distributor's general ledger. The Commodity Accounts Analysis Workform provides a tool to assess if the principal activity in Accounts 1589 and 1588 for a specific year is reasonable and distributors must explain unreconciled variances greater than +/- 1% of IESO purchases. Distributors are required to submit a Commodity Accounts Analysis Workform for each year that has not previously been approved by the OEB for disposition.

Account 1589

The Commodity Accounts Analysis Workform compares the principal activity in the general ledger for Account 1589 to the expected principal balances based on monthly GA volumes, revenue, and costs.

The principal activity in Account 1589 recorded in 2025 was $(5,875,052) as identified in Table 9-3-82 below. The principal activity balance, after known adjustments of $(2,482,447) was $(8,357,499). This is compared to the expected principal balance in Account 1589 of $(7,847,591) calculated in Attachment 9-18, which results in an unreconciled difference of $(509,908). This represents 0.96% of Alectra Utilities 2025 IESO purchases in the Brampton RZ, which is within the OEB's threshold (+/- 1% of IESO purchases).

Table 9-3-82: Commodity Accounts Analysis Workform Summary

Description	Amount
Principal Activity in RSVA(GA)	(5,875,052)
Add Known Adjustments	(2,482,447)
Adjusted Principal Activity in RSVA(GA)	(8,357,499)
Expected Principal Activity in RSVA(GA)	(7,847,591)
Variance $	(509,908)
Total 2025 IESO Purchases	52,992,574
Absolute Variance as a % of IESO Purchases	**0.96 %**

Account 1588

The Commodity Accounts Analysis Workform also includes a reasonability test for Account 1588, RSVA Power, and compares the annual Account 1588 variance to the Cost of Power purchases in the respective year.

The transactions in Account 1588 recorded in 2025 was $958,770 as identified in Table 9-3-83 below. The transactions, after principal adjustments of $666,633 was $1,625,403. This is compared to the power purchased of $357,884,794, which represents 0.45% of purchases, which is within the OEB's threshold.

Table 9-3-83: Account 1588 Power Summary

Description	Amount
Principal Activity in RSVA(Power)	958,770
Add Known Adjustments	666,633
Total Activity in 2025	1,625,403
Account 4705 - Power Purchased	357,884,794
Absolute Variance as a % of Power Purchased	**0.45 %**

1.1.3. PowerStream RZ

The Group 1 balances as of December 31, 2025, in the amount of $(20,218,139) have been adjusted for the following items to determine the amount for disposition of $(39,375,946) as identified in Table 9-3-84, below:

- Group 1 balances approved for disposition in the 2026 Annual Filing have been excluded;
- Principal adjustments which are not included in the audited financial statements have been identified separately as an adjustment to the balance requested for disposition. Consequently, the account balances on Tab 2a. DVA Continuity Schedule differ from the annual RRR filing;
- Projected carrying charges for each Group 1 Account balance to the proposed rate rider implementation date are included (i.e., the amount for disposition includes projected carrying charges to December 31, 2026); and
- Only eligible residual balances in Account 1595, for which rate riders have expired, are included. The disposition of these balances is requested two years after expiration.

Table 9-3-84: Group 1 Balances for Disposition – PowerStream RZ

Description	Amount
Group 1 Account Balances as of December 31, 2025	**(20,218,139)**
Subtract 2026 Annual Filing Disposition (EB-2025-0055) - Recovery from Customers	16,110,706
Add Principal Adjustments	(3,170,093)
Add Projected Carrying Charges	(1,029,975)
Deduct 1595 Residual Balances to be disposed in a future rate proceeding	(1,152,967)
Adjusted Group 1 Account Balances for Disposition - Repayment to Customers	**(39,375,946)**

Alectra Utilities has computed the disposition threshold for the PowerStream RZ, based on the adjusted Group 1 balances to be $-0.0042/kWh, as identified in Table 9-3-85, below.

Table 9-3-85: Calculation of Disposition Threshold – PowerStream RZ

Description	Account	Amount
Low Voltage	1550	(1,647,027)
Smart Meter Entity Charge	1551	(518,922)
RSVA - Wholesale Market Service Charge excluding CBR	1580	(18,188,555)
RSVA - Wholesale Market Service Charge - Capacity Based Recovery ("CBR") Class B	1580	7,093,127
RSVA - Retail Transmission Network Charge	1584	2,680,077
RSVA - Retail Transmission Connection Charge	1586	(1,575,939)
RSVA - Power	1588	(4,767,895)
RSVA - Global Adjustment	1589	(2,319,408)
Disposition and Recovery/Refund of Regulatory Balances	1595	(973,599)
Group 1 Account Balances as of December 31, 2025		**(20,218,139)**
Subtract 2026 Annual Filing Disposition (EB-2025-0055) - Recovery from Customers		16,110,706
Add Principal Adjustments		(3,170,093)
Add Projected Carrying Charges		(1,029,975)
Deduct 1595 Residual Balances to be disposed in a future		(1,152,967)
Adjusted Group 1 Account Balances for Disposition - Repayment to Customers		**(39,375,946)**
2027 kWhs		9,467,607,480
Threshold Test $/kWh		**-0.0042**

Alectra Utilities has completed and filed the DVA Continuity Schedule as Attachment 9-3 for the PowerStream RZ. Alectra Utilities has reconciled the Group 1 balances in the 2025 RRR, section 2.1.7 for the PowerStream RZ. The variance to the RRR balance is equal to the principal adjustments made in the current disposition period. A reconciliation of the balance requested for disposition is provided in Table 9-3-86, below. Alectra Utilities confirms that the last OEB approved balance of $16,110,706 for the PowerStream RZ has been transferred to Account 1595, and that residual balances in Account 1595 Sub-accounts for each vintage year have only been disposed once. Further, Alectra Utilities has confirmed that the proposed load forecast for 2027 is used for the billing determinants to calculate the rater riders.

Alectra Utilities relied upon the OEB's prescribed interest rates to calculate carrying charges on the deferral and variance account balances. The prescribed interest rates of 2.55% for Q1 2026 was used to calculate forecasted interest for 2026. No adjustments have been made to any deferral and variance account balances previously approved by the OEB on a final basis.

Table 9-3-86: Deferral and Variance Account Reconciliation – PowerStream RZ

Account Description	Account	Principal Amounts as of Dec 31, 2025	Carrying Charges to Dec 31, 2025	Principal Disposition during 2026	Interest Disposition during 2026	Projected Carrying Charges to Dec 31, 2026	Total Disposition before Principal Adjustment	Principal Adjustment	Projected Carrying Charges to December 31, 2026	1595 Balances Not Claimed in 2026	Total Disposition
Group 1 Accounts:											
Low Voltage	1550	(1,630,813)	(16,214)	84,360	3,237	(39,435)	(1,598,865)				(1,598,865)
Smart Meter Entity Charge	1551	(493,894)	(25,028)	323,935	21,001	(4,334)	(178,319)				(178,319)
RSVA - Wholesale Market Service Charge excluding CBR	1580	(18,138,807)	(49,748)	2,889,215	31,102	(388,865)	(15,657,103)				(15,657,103)
RSVA - Wholesale Market Service Charge - CBR B	1580	6,947,226	145,901	(3,231,217)	(115,497)	94,758	3,841,173				3,841,173
RSVA - Retail Transmission Network Charge	1584	2,515,201	164,876	(2,995,629)	(170,842)	(12,251)	(498,645)				(498,645)
RSVA - Retail Transmission Connection Charge	1586	(1,552,721)	(23,218)	369,318	12,645	(30,177)	(1,224,154)				(1,224,154)
RSVA - Power	1588	(4,784,002)	16,108	1,603,213	17,518	(81,110)	(3,228,273)	1,483,363	37,826		(1,707,084)
Sub-total not including RSVA Power Global Adjustment		**(17,137,809)**	**212,677**	**(956,804)**	**(200,838)**	**(461,413)**	**(18,544,186)**	**1,483,363**	**37,826**		**(17,022,997)**
RSVA - Power Global Adjustment	1589	(2,563,121)	243,713	(14,200,573)	(630,670)	(427,473)	(17,578,126)	(4,653,456)	(118,663)		(22,350,245)
Total including RSVA Power Global Adjustment		**(19,700,931)**	**456,391**	**(15,157,377)**	**(831,508)**	**(888,887)**	**(36,122,313)**	**(3,170,093)**	**(80,837)**		**(39,373,242)**
Disposition and Recovery/Refund of Regulatory Balances (2018)	1595	—	—	—	—	—	—			—	—
Disposition and Recovery/Refund of Regulatory Balances (2019)	1595	—	—	—	—	—	—			—	—
Disposition and Recovery/Refund of Regulatory Balances (2020)	1595	—	—	—	—	—	—			—	—
Disposition and Recovery/Refund of Regulatory Balances (2021)	1595	—	—	(807)	(45)	(21)	(873)			(873)	—
Disposition and Recovery/Refund of Regulatory Balances (2022)	1595	66,534	205,849	(66,618)	(205,852)	(2)	(89)			(89)	—
Disposition and Recovery/Refund of Regulatory Balances (2023)	1595	(240,605)	127,083	238,039	(127,156)	(65)	(2,704)			—	(2,704)
Disposition and Recovery/Refund of Regulatory Balances (2024)	1595	(3,214,358)	2,804,149	2,863,508	(2,822,890)	(8,947)	(378,538)			(378,538)	—
Disposition and Recovery/Refund of Regulatory Balances (2025)	1595	(2,008,465)	1,286,213	—	—	(51,216)	(773,468)			(773,468)	—
Total 1595		**(5,396,893)**	**4,423,294**	**3,034,122**	**(3,155,943)**	**(60,251)**	**(1,155,671)**	**—**	**—**	**(1,152,967)**	**(2,704)**
Total Amount for Disposition		**(25,097,824)**	**4,879,685**	**(12,123,255)**	**(3,987,451)**	**(949,138)**	**(37,277,983)**	**(3,170,093)**	**(80,837)**	**(1,152,967)**	**(39,375,946)**

Alectra Utilities is seeking a one-year disposition period for the Group 1 balances for the PowerStream RZ. This approach is consistent with the EDDVAR Report which states on page 6 that “the default disposition period used to clear the account balances through a rate rider should be one year”.

Wholesale Market Participants (“WMPs”)

WMPs participate directly in the IESO administered market and settle commodity and market-related charges directly with the IESO. Alectra Utilities has established separate rate riders to dispose of the balances in the RSVAs for WMPs. The balances in Account 1588 RSVA – Power, Account 1580 RSVA – Wholesale Market Service Charge (including CBR) and Account 1589 RSVA – Global Adjustment have not been allocated to WMPs.

Global Adjustment and Capacity Based Response Disposition

Alectra Utilities has also established separate rate riders to dispose of the GA and CBR account balances for the PowerStream RZ. The GA rate rider is only applicable to non-RPP customers, and the CBR rate rider is only applicable to Class B customers. Alectra Utilities’ Class A customers are invoiced actual GA and CBR, therefore, none of the variance in the GA and CBR account balance is attributed to these customers.

There were 29 Alectra Utilities customers in the PowerStream RZ that transitioned between Class A and Class B during 2025 under the IESO’s Industrial Conservation Initiative (“ICI”). These transition customers paid GA and CBR during the period they were Class B customers. As such, these customers will only be allocated the portion of the GA and CBR account balance which accrued to them as a Class B customer.

These GA and CBR amounts will be settled through twelve equal adjustments to bills. These customers will not be charged or refunded the general GA and CBR rate riders.

Table 9-3-87 below identifies the GA and CBR balances disposed of through rate riders and specific bill adjustments.

Alectra Utilities requests disposition of its total GA balance of $(22,350,245), of which $(21,912,773) will be disposed of via rate rider; and $(437,472) will be disposed of via specific bill adjustments, as discussed above. Alectra Utilities requests disposition of its total CBR balance of $3,841,173, of which $3,811,832 will be disposed of via rate rider; and $29,341 will be disposed of via specific bill adjustments, as discussed above. Tab "6.1a GA Allocation" and "6.2a CBR B Allocation" in the DVA Continuity Schedule present the detailed calculation of the bill adjustments.

Table 9-3-87: Disposition of GA and CBR Balances – PowerStream RZ

Description	Amount
Global Adjustment - Non-RPP Class B Customers	(21,912,773)
Global Adjustment - Transition Customers	(437,472)
Class B Non-RPP Customers only - GA Rate Rider/Bill Adjustment	**(22,350,245)**
Capacity Based Recovery - Non-RPP Class B Customers	3,811,832
Capacity Based Recovery - Transition Customers	29,341
Class B Non-RPP Customers only - CBR Rate Rider/Bill Adjustment	**3,841,173**

A summary of the rate riders applicable to each group of customers is identified in Table 9-3-88 below.

Table 9-3-88: Rate Riders by Customer Group – PowerStream RZ

Customers	DVA Rate Rider 1 [1]	DVA Rate Rider 2 [2]	CBR B Rate Rider [3] (if applicable)	GA Rate Rider	Specific Bill Adjustment
WMPs	x				
Class A (Full Year)	x	x			
Transition Customers	x	x			x
Class B non-RPP Customers (Full Year)	x	x	x	x	
Class B RPP Customers	x	x	x		
1. DVA Rate Rider 1 = disposition of low voltage, SME, Network, Connection, IRM balances					
2. DVA Rate Rider 2 = disposition of Power and Wholesale Market Service Charges (excluding CBR)					
3. If the allocated CBR B amount does not produce a rate rider in one or more rate class, the entire balance is transferred into Account 1580 WMS control account					

WMPs are charged DVA Rate Rider 1 only, which includes account balances for low voltage charges, retail transmission network charges, and retail transmission connection charges.

Class A customers are charged the sum of DVA Rate Rider 1 and DVA Rate Rider 2, the latter of which includes account balances for power and wholesale market service charges excluding CBR.

Transition customers are charged the sum of DVA Rate Rider 1 and DVA Rate Rider 2; and a customer specific bill adjustment for their portion of the GA and CBR account balances.

Class B, non-RPP customers are charged the sum of DVA Rate Riders 1 and 2; and the GA and CBR Rate Rider.

Class B, RPP customers are charged the sum of DVA Rate Riders 1 and 2; and the CRB Rate Rider.

The Group 1 DVAs disposition by customer group is identified in Table 9-3-89, below.

Table 9-3-89: Group 1 DVAs Disposition by Customer Group – PowerStream RZ

Description	Account	Amount
Low Voltage	1550	(1,598,865)
Smart Meter Entity Charge (Residential and GS<50kW Classes Only)	1551	(178,319)
Retail Transmission Network Charge	1584	(498,645)
Retail Transmission Connection Charge	1586	(1,224,154)
Disposition and Recovery/Refund of Regulatory Balances	1595	(2,704)
All Customers - DVA Rate Rider 1		**(3,502,687)**
Power	1588	(1,707,084)
Wholesale Market Service Charge excluding CBR	1580	(15,657,103)
All Customers ex WMPs - DVA Rate Rider 2		**(17,364,187)**
Wholesale Market Service Charge - CBR Class B	1580	3,811,832
Capacity Based Recovery - Transition Customers	1580	29,341
All Class B Customers ex WMPs - CBR B Rate Rider/Bill Adjustment		**3,841,173**
Global Adjustment - Non-RPP Class B Customers	1589	(21,912,773)
Global Adjustment - Transition Customers	1589	(437,472)
Class B Non-RPP Customers only - GA Rate Rider/Bill Adjustment		**(22,350,245)**
Total (Repayment to)/Recovery from Customers		**(39,375,946)**
Disposition via Rate Rider		(38,967,815)
Global Adjustment - Transition Customers		(437,472)
Capacity Based Recovery - Transition Customers		29,341

All balances claimed are allocated to the rate classes based on the default cost allocation methodology as identified in the EDDVAR report.

The billing determinants, billing adjustments and calculation of the rate riders are provided in Tabs 4 through 7 in the DVA Continuity Schedule filed as Attachment 9-3. Alectra Utilities requests disposition of the PowerStream RZ adjusted Group 1 balances, through the rate riders identified in Table 9-3-90, below.

Table 9-3-90: Deferral and Variance Account Riders – PowerStream RZ

Customer Class	Deferral/ Variance Account Rate Rider		Deferral/ Variance Account Rate Rider for Non-WMP		Global Adjustment Rate Rider Non-RPP Class B		CBR B Rate Rider Class B Consumer	
	$/kWh	$/kW	$/kWh	$/kW	$/kWh	$/kW	$/kWh	$/kW
Residential	(0.0022)				(0.0079)		0.0005	
General Service Less Than 50 kW	(0.0022)				(0.0079)		0.0005	
General Service 50 To 4,999 kW		(0.1353)		(0.7083)	(0.0079)			0.1789
Large Use		(1.1261)						
Unmetered Scattered Load	(0.0022)				(0.0079)		0.0005	
Street Lighting		(0.7770)			(0.0079)			0.1826
Sentinel Lighting		(0.8021)			(0.0079)			0.1885

Commodity Accounts Analysis Workform

The Commodity Accounts Analysis Workform for the PowerStream RZ is filed as Attachment 9-19. The Commodity Accounts Analysis Workform assesses the reasonability of Account 1589, RSVA GA and Account 1588, RSVA Power through a calculation of expected principal balances and compares the expected amounts to the amounts reported in the distributor's general ledger. The Commodity Accounts Analysis Workform provides a tool to assess if the principal activity in Accounts 1589 and 1588 for a specific year is reasonable and distributors must explain unreconciled variances greater than +/- 1% of IESO purchases. Distributors are required to submit a Commodity Accounts Analysis Workform for each year that has not previously been approved by the OEB for disposition.

Account 1589

The Commodity Accounts Analysis Workform compares the principal activity in the general ledger for Account 1589 to the expected principal balances based on monthly GA volumes, revenue, and costs.

The principal activity in Account 1589 recorded in 2025 was $(16,763,694) as identified in Table 9-3-91 below. The principal activity balance, after known adjustments of $(4,629,416) was $(21,393,110). This is compared to the expected principal balance in Account 1589 of $(20,040,680) calculated in Attachment 9-19, which results in an unreconciled difference of $(1,352,430). This represents 0.99% of Alectra Utilities 2025 IESO purchases in the PowerStream RZ, which is within the OEB's threshold (+/- 1% of IESO purchases).

Table 9-3-91: Commodity Accounts Analysis Workform Summary

Description	Amount
Principal Activity in RSVA(GA)	(16,763,694)
Add Known Adjustments	(4,629,416)
Adjusted Principal Activity in RSVA(GA)	(21,393,110)
Expected Principal Activity in RSVA(GA)	(20,040,680)
Variance $	(1,352,430)
Total 2025 IESO Purchases	136,615,784
Absolute Variance as a % of IESO Purchases	**0.99 %**

Account 1588

The Commodity Accounts Analysis Workform also includes a reasonability test for Account 1588, RSVA Power, and compares the annual Account 1588 variance to the Cost of Power purchases in the respective year.

The transactions in Account 1588 recorded in 2025 was $(3,180,789) as identified in Table 9-3-92 below. The transactions, after principal adjustments of $1,483,363 was $(1,697,426).This is compared to the power purchased of $808,925,218, which represents 0.21% of purchases, which is within the OEB's threshold.

Table 9-3-92: Account 1588 Power Summary

Description	Amount
Principal Activity in RSVA(Power)	(3,180,789)
Add Known Adjustments	1,483,363
Total Activity in 2025	(1,697,426)
Account 4705 - Power Purchased	808,925,218
Absolute Variance as a % of Power Purchased	**0.21 %**

1.1.4. Enersource RZ

The Group 1 balances as of December 31, 2025, in the amount of $(11,091,774) have been adjusted for the following items to determine the amount for disposition of $(28,883,465) as identified in Table 9-3-93, below:

- Group 1 balances approved for disposition in the 2026 Annual Filing have been excluded;
- Principal adjustments which are not included in the audited financial statements have been identified separately as an adjustment to the balance requested for disposition. Consequently, the account balances on Tab 2a. DVA Continuity Schedule differ from the annual RRR filing;
- Projected carrying charges for each Group 1 Account balance to the proposed rate rider implementation date are included (i.e., the amount for disposition includes projected carrying charges to December 31, 2026); and
- Only eligible residual balances in Account 1595, for which rate riders have expired, are included. The disposition of these balances is requested two years after expiration.

1 **Table 9-3-93: Group 1 Balances for Disposition – Enersource RZ**

Description	Amount
Group 1 Account Balances as of December 31, 2025	**(11,091,774)**
Subtract 2026 Annual Filing Disposition (EB-2025-0055) - Recovery from Customers	17,304,502
Add Principal Adjustments	1,417,869
Add Projected Carrying Charges	(815,670)
Deduct 1595 Residual Balances to be disposed in a future rate proceeding	1,089,389
Adjusted Group 1 Account Balances for Disposition - Repayment to Customers	**(28,883,465)**

Alectra Utilities has computed the disposition threshold for the Enersource RZ, based on the adjusted Group 1 balances to be $0.0041/kWh, as identified in Table 9-3-94, below.

Table 9-3-94: Calculation of Disposition Threshold – Enersource RZ

Description	Account	Amount
Low Voltage	1550	(1,069,967)
Smart Meter Entity Charge	1551	(255,422)
RSVA - Wholesale Market Service Charge excluding CBR	1580	(13,427,092)
RSVA - Wholesale Market Service Charge - Capacity Based Recovery ("CBR") Class B	1580	5,764,881
RSVA - Retail Transmission Network Charge	1584	6,588,013
RSVA - Retail Transmission Connection Charge	1586	757,391
RSVA - Power	1588	(5,859,981)
RSVA - Global Adjustment	1589	(4,686,490)
Disposition and Recovery/Refund of Regulatory Balances	1595	1,096,893
Group 1 Account Balances as of December 31, 2025		**(11,091,774)**
Subtract 2026 Annual Filing Disposition (EB-2025-0055) - Recovery from Customers		17,304,502
Add Principal Adjustments		1,417,869
Add Projected Carrying Charges		(815,670)
Deduct 1595 Residual Balances to be disposed in a future rate proceeding		1,089,389
Adjusted Group 1 Account Balances for Disposition - Repayment to Customers		**(28,883,465)**
2027 kWhs		7,131,332,240
Threshold Test $/kWh		**0.0041**

Alectra Utilities has completed and filed the DVA Continuity Schedule as Attachment 9-4 for the Enersource RZ. Alectra Utilities has reconciled the Group 1 balances in the 2025 RRR, section 2.1.7 for the Enersource RZ. The variance to the RRR balance is equal to the principal adjustments made in the current disposition period. A reconciliation of the balance requested for disposition is provided in Table 9-3-95, below. Alectra Utilities confirms that the last OEB-approved balance of $17,304,502 for the Enersource RZ has been transferred to Account 1595, and that residual balances in Account 1595 Sub-accounts for each vintage year have only been disposed once. Further, Alectra Utilities has confirmed that the proposed load forecast for 2027 is used for the billing determinants to calculate the rater riders.

Alectra Utilities relied upon the OEB's prescribed interest rates to calculate carrying charges on the deferral and variance account balances. The prescribed interest rates of 2.55% for Q1 2026 was used to calculate forecasted interest for 2026. No adjustments have been made to any deferral and variance account balances previously approved by the OEB on a final basis.

Table 9-3-95: Deferral and Variance Account Reconciliation – Enersource RZ

Account Description	Account	Principal Amounts as of Dec 31, 2025	Carrying Charges to Dec 31, 2025	Principal Disposition during 2026	Interest Disposition during 2026	Projected Carrying Charges to Dec 31, 2026	Total Disposition before Principal Adjustment	Principal Adjustment	Projected Carrying Charges to December 31, 2026	1595 Balances Not Claimed in 2026	Total Disposition
Group 1 Accounts:											
Low Voltage	1550	(1,068,827)	(1,140)	50,187	(2,447)	(25,975)	(1,048,202)				(1,048,202)
Smart Meter Entity Charge	1551	(242,768)	(12,654)	162,013	10,635	(2,059)	(84,833)				(84,833)
RSVA - Wholesale Market Service Charge excluding CBR	1580	(13,390,705)	(36,387)	2,225,636	22,055	(284,709)	(11,464,111)				(11,464,111)
RSVA - Wholesale Market Service Charge - CBR B	1580	5,638,436	126,445	(2,666,730)	(100,159)	75,779	3,073,771				3,073,771
RSVA - Retail Transmission Network Charge	1584	6,325,034	262,979	(4,133,212)	(232,555)	55,891	2,278,138				2,278,138
RSVA - Retail Transmission Connection Charge	1586	701,244	56,146	(643,353)	(44,497)	1,476	71,017				71,017
RSVA - Power	1588	(5,272,796)	(587,186)	(977,963)	403,042	(159,394)	(6,594,297)	1,304,319	33,260		(5,256,718)
Sub-total not including RSVA Power Global Adjustment		**(7,310,381)**	**(191,797)**	**(5,983,422)**	**56,074**	**(338,992)**	**(13,768,518)**	**1,304,319**	**33,260**		**(12,430,938)**
RSVA - Power Global Adjustment	1589	(5,178,782)	492,292	(10,684,248)	(721,127)	(404,507)	(16,496,372)	113,550	2,896		(16,379,927)
Total including RSVA Power Global Adjustment		**(12,489,163)**	**300,496**	**(16,667,671)**	**(665,054)**	**(743,499)**	**(30,264,890)**	**1,417,869**	**36,156**		**(28,810,865)**
Disposition and Recovery/Refund of Regulatory Balances (2018)	1595	—	—	—	—	—	—			—	—
Disposition and Recovery/Refund of Regulatory Balances (2019)	1595	—	—	—	—	—	—			—	—
Disposition and Recovery/Refund of Regulatory Balances (2020)	1595	—	—	—	—	—	—			—	—
Disposition and Recovery/Refund of Regulatory Balances (2021)	1595	—	—	—	—	—	—			—	—
Disposition and Recovery/Refund of Regulatory Balances (2022)	1595	(167,458)	138,783	167,018	(138,795)	(11)	(463)			(463)	—
Disposition and Recovery/Refund of Regulatory Balances (2023)	1595	(774,911)	722,071	—	—	(19,760)	(72,600)			—	(72,600)
Disposition and Recovery/Refund of Regulatory Balances (2024)	1595	(998,842)	2,534,820	—	—	(25,470)	1,510,508			1,510,508	—
Disposition and Recovery/Refund of Regulatory Balances (2025)	1595	(2,473,912)	2,116,341			(63,085)	(420,656)			(420,656)	
Total 1595		**(4,415,122)**	**5,512,015**	**167,018**	**(138,795)**	**(108,327)**	**1,016,789**	**—**	**—**	**1,089,389**	**(72,600)**
Total Amount for Disposition		**(16,904,285)**	**5,812,511**	**(16,500,653)**	**(803,849)**	**(851,826)**	**(29,248,101)**	**1,417,869**	**36,156**	**1,089,389**	**(28,883,465)**

Alectra Utilities is seeking a one-year disposition period for the Group 1 balances for the Enersource RZ. This approach is consistent with the EDDVAR Report which states on page 6 that “the default disposition period used to clear the account balances through a rate rider should be one year”.

Wholesale Market Participants (“WMPs”)

WMPs participate directly in the IESO administered market and settle commodity and market-related charges directly with the IESO. Alectra Utilities has established separate rate riders to dispose of the balances in the RSVAs for WMPs. The balances in Account 1588 RSVA – Power, Account 1580 RSVA – Wholesale Market Service Charge (including CBR) and Account 1589 RSVA – Global Adjustment have not been allocated to WMPs.

Global Adjustment and Capacity Based Response Disposition

Alectra Utilities has also established separate rate riders to dispose of the GA and CBR account balances for the Enersource RZ. The GA rate rider is only applicable to non-RPP customers, and the CBR rate rider is only applicable to Class B customers. Alectra Utilities’ Class A customers are invoiced actual GA, therefore, none of the variance in the GA and CBR account balance is attributed to these customers.

There were 21 Alectra Utilities customers in the Enersource RZ that transitioned between Class A and Class B during 2025 under the IESO’s Industrial Conservation Initiative (“ICI”). These transition customers paid GA and CBR during the period they were Class B customers. As such, these customers will only be allocated the portion of the GA and CBR account balance which accrued to them as a Class B customer.

These GA and CBR amounts will be settled through twelve equal adjustments to bills. These customers will not be charged or refunded the general GA and CBR rate riders.

Table 9-3-96 below identifies the GA and CBR balances disposed of through rate riders and specific bill adjustments.

Alectra Utilities requests disposition of its total GA balance of $(16,379,927), of which $(16,171,317) will be disposed of via rate rider and $(208,610) will be disposed of via specific bill adjustments, as discussed above. Alectra Utilities requests disposition of its total CBR balance of $3,073,771, of which $3,055,685 will be disposed of via rate rider and $18,086 will be disposed of via specific bill adjustments, as discussed above. Tab "6.1a GA Allocation" and "6.2a CBR B Allocation" in the DVA Continuity Schedule present the detailed calculation of the bill adjustments.

Table 9-3-96: Disposition of GA Balances – Enersource RZ

Description	Amount
Global Adjustment - Non-RPP Class B Customers	(16,171,317)
Global Adjustment - Transition Customers	(208,610)
Class B Non-RPP Customers only - GA Rate Rider/Bill Adjustment	**(16,379,927)**
Capacity Based Recovery - Non-RPP Class B Customers	3,055,685
Capacity Based Recovery - Transition Customers	18,086
Class B Non-RPP Customers only - CBR Rate Rider/Bill Adjustment	**3,073,771**

A summary of the rate riders applicable to each group of customers is identified in Table 9-3-97 below.

Table 9-3-97: Rate Riders by Customer Group – Enersource RZ

Customers	DVA Rate Rider 1 [1]	DVA Rate Rider 2 [2]	CBR B Rate Rider [3] (if applicable)	GA Rate Rider	Specific Bill Adjustment
WMPs	x				
Class A (Full Year)	x	x			
Transition Customers	x	x			x
Class B non-RPP Customers (Full Year)	x	x	x	x	
Class B RPP Customers	x	x	x		
1. DVA Rate Rider 1 = disposition of low voltage, SME, Network, Connection, IRM balances					
2. DVA Rate Rider 2 = disposition of Power and Wholesale Market Service Charges (excluding CBR)					
3. If the allocated CBR B amount does not produce a rate rider in one or more rate class, the entire balance is transferred into Account 1580 WMS control account					

WMPs are charged DVA Rate Rider 1 only, which includes account balances for low voltage charges, retail transmission network charges, and retail transmission connection charges.

Class A customers are charged the sum of DVA Rate Rider 1 and DVA Rate Rider 2, the latter of which includes account balances for power and wholesale market service charges excluding CBR.

Transition customers are charged the sum of DVA Rate Rider 1 and DVA Rate Rider 2; and a customer specific bill adjustment for their portion of the GA and CBR account balances.

Class B, non-RPP customers are charged the sum of DVA Rate Riders 1 and 2; and the GA and CBR Rate Rider.

Class B RPP customers are charged the sum of DVA Rate Riders 1 and 2; and the CBR Rate Rider.

The Group 1 DVAs disposition by customer group is identified in Table 9-3-98, below.

Table 9-3-98: Group 1 DVAs Disposition by Customer Group – Enersource RZ

Description	Account	Amount
Low Voltage	1550	(1,048,202)
Smart Meter Entity Charge (Residential and GS<50kW Classes Only)	1551	(84,833)
Retail Transmission Network Charge	1584	2,278,138
Retail Transmission Connection Charge	1586	71,017
Disposition and Recovery/Refund of Regulatory Balances	1595	(72,600)
All Customers - DVA Rate Rider 1		**1,143,520**
Power	1588	(5,256,718)
Wholesale Market Service Charge excluding CBR	1580	(11,464,111)
All Customers ex WMPs - DVA Rate Rider 2		**(16,720,829)**
Wholesale Market Service Charge - CBR Class B	1580	3,055,685
Capacity Based Recovery - Transition Customers	1580	18,086
All Class B Customers ex WMPs - CBR B Rate Rider/Bill Adjustment		**3,073,771**
Global Adjustment - Non-RPP Class B Customers	1589	(16,171,317)
Global Adjustment - Transition Customers	1589	(208,610)
Class B Non-RPP Customers only - GA Rate Rider/Bill Adjustment		**(16,379,927)**
Total (Repayment to)/Recovery from Customers		**(28,883,465)**
Disposition via Rate Rider		(28,692,941)
Global Adjustment - Transition Customers		(208,610)
Capacity Based Recovery - Transition Customers		18,086

All balances claimed are allocated to the rate classes based on the default cost allocation methodology as identified in the EDDVAR report.

The billing determinants, billing adjustments and calculation of the rate riders are provided in Tabs 4 through 7 in the DVA Continuity Schedule filed as Attachment 9-4. Alectra Utilities requests disposition of the Enersource RZ adjusted Group 1 balances, through the rate riders identified in Table 9-3-99, below.

Table 9-3-99: Deferral and Variance Account Riders – Enersource RZ

Customer Class	Deferral/ Variance Account Rate Rider		Deferral/ Variance Account Rate Rider for Non-WMP		Global Adjustment Rate Rider Non-RPP Class B		CBR B Rate Rider Class B Consumer	
	$/kWh	$/kW	$/kWh	$/kW	$/kWh	$/kW	$/kWh	$/kW
Residential	(0.0022)				(0.0071)		0.0006	
General Service Less Than 50 kW	(0.0022)				(0.0071)		0.0006	
General Service 50 To 499 kW		(0.7525)			(0.0071)			0.2089
General Service 500 To 4,999 kW		0.0781		(1.0699)	(0.0071)			0.2504
Large Use		(1.2754)						
Unmetered Scattered Load	(0.0022)				(0.0071)		0.0006	
Street Lighting		(0.8063)			(0.0071)			0.2235

Commodity Accounts Analysis Workform

The Commodity Accounts Analysis Workform for the Enersource RZ is filed as Attachment 9-20. The Commodity Accounts Analysis Workform assesses the reasonability of Account 1589, RSVA GA and Account 1588, RSVA Power through a calculation of expected principal balances and compares the expected amounts to the amounts reported in the distributor's general ledger. The Commodity Accounts Analysis Workform provides a tool to assess if the principal activity in Accounts 1589 and 1588 for a specific year is reasonable and distributors must explain unreconciled variances greater than +/- 1% of IESO purchases. Distributors are required to submit a Commodity Accounts Analysis Workform for each year that has not previously been approved by the OEB for disposition.

Account 1589

The Commodity Accounts Analysis Workform compares the principal activity in the general ledger for Account 1589 to the expected principal balances based on monthly GA volumes, revenue, and costs.

The principal activity in Account 1589 recorded in 2025 was $(15,863,030) as identified in Table 9-3-100 below. The principal activity balance after known adjustments of $152,566 was $(15,710,464). This is compared to the expected principal balance in Account 1589 of $(14,984,922) calculated in Attachment 9-20, which results in an unreconciled difference of $(725,542). This represents 0.67% of Alectra Utilities 2025 IESO purchases in the Enersource RZ, which is within the OEB's threshold (+/- 1% of IESO purchases).

Table 9-3-100: Commodity Accounts Analysis Workform Summary

Description	Amount
Principal Activity in RSVA(GA)	(15,863,030)
Add Known Adjustments	152,566
Adjusted Principal Activity in RSVA(GA)	(15,710,464)
Expected Principal Activity in RSVA(GA)	(14,984,922)
Variance $	(725,542)
Total 2025 IESO Purchases	109,019,503
Absolute Variance as a % of IESO Purchases	**0.67 %**

Account 1588

The Commodity Accounts Analysis Workform also includes a reasonability test for Account 1588, RSVA Power, and compares the annual Account 1588 variance to the Cost of Power purchases in the respective year.

The transactions in Account 1588 recorded in 2025 was $(6,250,759) as identified in Table 9-3-101 below. The transactions, after principal adjustments of $1,304,319 was $(4,946,440). This is compared to the power purchased of $572,728,918, which represents 0.86% of purchases, which is within the OEB's threshold.

Table 9-3-101: Account 1588 Power Summary

Description	Amount
Principal Activity in RSVA(Power)	(6,250,759)
Add Known Adjustments	1,304,319
Total Activity in 2025	(4,946,440)
Account 4705 - Power Purchased	572,728,918
Absolute Variance as a % of Power Purchased	**0.86 %**

1.1.5. Guelph Hydro RZ

The Group 1 balances as of December 31, 2025, in the amount of $888,930 have been adjusted for the following items to determine the amount for disposition of $(1,917,911) as identified in Table 9-3-102, below:

- Group 1 balances approved for disposition in the 2026 Annual Filing have been excluded;
- Principal adjustments which are not included in the audited financial statements have been identified separately as an adjustment to the balance requested for disposition Consequently, the account balances on Tab 2a. DVA Continuity Schedule differ from the annual RRR filing;
- Projected carrying charges for each Group 1 Account balance to the proposed rate rider implementation date are included (i.e., the amount for disposition includes projected carrying charges to December 31, 2026); and
- Only eligible residual balances in Account 1595, for which rate riders have expired, are included. The disposition of these balances is requested two years after expiration.

1 **Table 9-3-102: Group 1 Balances for Disposition – Guelph Hydro RZ**

Description	Amount
Group 1 Account Balances as of December 31, 2025	**888,930**
Subtract 2026 Annual Filing Disposition (EB-2025-0055) - Recovery from Customers	1,716,791
Add Principal Adjustments	(494,861)
Add Projected Carrying Charges	(77,284)
Deduct 1595 Residual Balances to be disposed in a future rate proceeding	517,905
Adjusted Group 1 Account Balances for Disposition - Repayment to Customers	**(1,917,911)**

2

3 Alectra Utilities has computed the disposition threshold for the Guelph Hydro RZ, based on the
4 adjusted Group 1 balances to be $-0.0012/kWh, as identified in Table 9-3-103, below.

5 **Table 9-3-103: Calculation of Disposition Threshold – Guelph Hydro RZ**

Description	Account	Amount
Low Voltage	1550	(59,382)
Smart Meter Entity Charge	1551	(70,564)
RSVA - Wholesale Market Service Charge excluding CBR	1580	(3,407,061)
RSVA - Wholesale Market Service Charge - Capacity Based Recovery ("CBR") Class B	1580	857,244
RSVA - Retail Transmission Network Charge	1584	45,976
RSVA - Retail Transmission Connection Charge	1586	(438,919)
RSVA - Power	1588	(1,208,300)
RSVA - Global Adjustment	1589	4,535,395
Disposition and Recovery/Refund of Regulatory Balances	1595	634,541
Group 1 Account Balances as of December 31, 2025		**888,930**
Subtract 2026 Annual Filing Disposition (EB-2025-0055) - Recovery from Customers		1,716,791
Add Principal Adjustments		(494,861)
Add Projected Carrying Charges		(77,284)
Deduct 1595 Residual Balances to be disposed in a future rate proceeding		517,905
Adjusted Group 1 Account Balances for Disposition - Recovery from Customers		**(1,917,911)**
2027 kWhs		1,662,001,551
Threshold Test $/kWh		**-0.0012**

6

Alectra Utilities has completed and filed the DVA Continuity Schedule as Attachment 9-5 for the Guelph Hydro RZ. Alectra Utilities has reconciled the Group 1 balances in the 2025 RRR, section 2.1.7 for the Guelph Hydro RZ. The variance to the RRR balance is equal to the principal adjustments made in the current disposition period. A reconciliation of the balance requested for disposition is provided in Table 9-3-104, below.

Alectra Utilities confirms that the last OEB approved balance of $1,716,791 for the Guelph Hydro RZ has been transferred to Account 1595, and that residual balances in Account 1595 Sub-accounts for each vintage year have only been disposed once. Further, Alectra Utilities has confirmed that the proposed load forecast for 2027 is used for the billing determinants to calculate the rater riders.

Alectra Utilities relied upon the OEB's prescribed interest rates to calculate carrying charges on the deferral and variance account balances. The prescribed interest rates of 2.55% for Q1 2026 was used to calculate forecasted interest for 2026. No adjustments have been made to any deferral and variance account balances previously approved by the OEB on a final basis.

Table 9-3-104: Deferral and Variance Account Reconciliation – Guelph Hydro RZ

Account Description	Account	Principal Amounts as of Dec 31, 2025	Carrying Charges to Dec 31, 2025	Principal Disposition during 2026	Interest Disposition during 2026	Projected Carrying Charges to Dec 31, 2026	Total Disposition before Principal Adjustment	Principal Adjustment	Projected Carrying Charges to December 31, 2026	1595 Balances Not Claimed in 2026	Total Disposition
Group 1 Accounts:											
Low Voltage	1550	(58,386)	(996)	19,246	756	(998)	(40,378)				(40,378)
Smart Meter Entity Charge	1551	(66,969)	(3,594)	44,826	3,029	(565)	(23,273)				(23,273)
RSVA - Wholesale Market Service Charge excluding CBR	1580	(3,402,133)	(4,928)	219,535	(4,233)	(81,156)	(3,272,916)				(3,272,916)
RSVA - Wholesale Market Service Charge - CBR B	1580	838,367	18,878	(393,227)	(14,239)	11,351	461,128				461,128
RSVA - Retail Transmission Network Charge	1584	49,385	(3,409)	174,592	5,653	5,711	231,933				231,933
RSVA - Retail Transmission Connection Charge	1586	(426,191)	(12,728)	446,676	16,746	522	25,026				25,026
RSVA - Power	1588	(1,257,388)	49,088	166,147	(36,871)	(27,827)	(1,106,851)	1,301,241	33,182		227,573
Sub-total not including RSVA Power Global Adjustment		**(4,323,316)**	**42,310**	**677,795**	**(29,158)**	**(92,961)**	**(3,725,330)**	**1,301,241**	**33,182**		**(2,390,907)**
											—
RSVA - Power Global Adjustment	1589	4,475,715	59,680	(2,321,129)	(92,454)	54,942	2,176,753	(1,796,102)	(45,801)		334,850
											—
Total including RSVA Power Global Adjustment		**152,398**	**101,990**	**(1,643,334)**	**(121,613)**	**(38,019)**	**(1,548,578)**	**(494,861)**	**(12,619)**		**(2,056,057)**
Disposition and Recovery/Refund of Regulatory Balances (2018)	1595	—	—	—	—	—	—			—	—
Disposition and Recovery/Refund of Regulatory Balances (2019)	1595	—	—	—	—	—	—			—	—
Disposition and Recovery/Refund of Regulatory Balances (2020)	1595	—	—	—	—	—	—			—	—
Disposition and Recovery/Refund of Regulatory Balances (2021)	1595	—	—	—	—	—	—			—	—
Disposition and Recovery/Refund of Regulatory Balances (2022)	1595	(42,259)	(5,898)	42,258	5,899	—	(1)			(1)	—
Disposition and Recovery/Refund of Regulatory Balances (2023)	1595	(128,263)	269,680	—	—	(3,271)	138,146			—	138,146
Disposition and Recovery/Refund of Regulatory Balances (2024)	1595	(228,024)	758,035	—	—	(5,815)	524,196			524,196	—
Disposition and Recovery/Refund of Regulatory Balances (2025)	1595	(688,667)	699,938	—	—	(17,561)	(6,290)			(6,290)	—
Total 1595		**(1,087,213)**	**1,721,754**	**42,258**	**5,899**	**(26,646)**	**656,051**	**—**	**—**	**517,905**	**138,146**
Total Amount for Disposition		**(934,815)**	**1,823,744**	**(1,601,077)**	**(115,714)**	**(64,665)**	**(892,526)**	**(494,861)**	**(12,619)**	**517,905**	**(1,917,911)**

Alectra Utilities is seeking a one-year disposition period for the Group 1 balances for the Guelph Hydro RZ. This approach is consistent with the EDDVAR Report which states on page 6 that "the default disposition period used to clear the account balances through a rate rider should be one year".

Wholesale Market Participants ("WMPs")

WMPs participate directly in the IESO administered market and settle commodity and market-related charges directly with the IESO. Alectra Utilities has established separate rate riders to dispose of the balances in the RSVAs for WMPs. The balances in Account 1588 RSVA – Power, Account 1580 RSVA – Wholesale Market Service Charge (including CBR) and Account 1589 RSVA – Global Adjustment have not been allocated to WMPs.

Global Adjustment and Capacity Based Response Disposition

Alectra Utilities has also established separate rate riders to dispose of the GA and CBR account balances for the Guelph Hydro RZ. The GA rate rider is only applicable to non-RPP customers, and the CBR rate rider is only applicable to Class B customers. Alectra Utilities' Class A customers are invoiced actual GA, therefore, none of the variance in the GA and CBR account balance is attributed to these customers.

There were 8 Alectra Utilities customers in the Guelph Hydro RZ that transitioned between Class A and Class B during 2025 under the IESO's Industrial Conservation Initiative ("ICI"). These transition customers paid GA and CBR during the period they were a Class B customer. As such, these customers will only be allocated the portion of the GA and CBR account balance, which accrued to them as a Class B customer.

These GA and CBR amounts will be settled through twelve equal adjustments to bills. This customer will not be charged or refunded the general GA and CBR rate riders.

Table 9-3-105 below identifies the GA and CBR balances disposed of through rate riders and specific bill adjustments.

Alectra Utilities requests disposition of its total GA balance of $334,850, of which $316,609 will be disposed of through a rate rider; and $18,241 will be disposed of through specific bill adjustments, as discussed above. Alectra Utilities requests disposition of its total CBR balance of $461,128, of which $452,732 will be disposed of through a rate rider; and $8,396 will be disposed of via specific bill adjustments, as discussed above. Tabs “6.1a GA Allocation” and “6.2a CBR B Allocation” in the DVA Continuity Schedule present the detailed calculation of the bill adjustments.

Table 9-3-105: Disposition of GA Balances – Guelph Hydro RZ

Description	Amount
Global Adjustment - Non-RPP Class B Customers	316,609
Global Adjustment - Transition Customers	18,241
Class B Non-RPP Customers only - GA Rate Rider/Bill Adjustment	**334,850**
Capacity Based Recovery - Non-RPP Class B Customers	452,732
Capacity Based Recovery - Transition Customers	8,396
Class B Non-RPP Customers only - CBR Rate Rider/Bill Adjustment	**461,128**

A summary of the rate riders applicable to each group of customers is identified in Table 9-3-106 below.

Table 9-3-106: Rate Riders by Customer Group – Guelph Hydro RZ

Customers	DVA Rate Rider 1 [1]	DVA Rate Rider 2 [2]	CBR B Rate Rider [3] (if applicable)	GA Rate Rider	Specific Bill Adjustment
WMPs	x				
Class A (Full Year)	x	x			
Transition Customers	x	x			x
Class B non-RPP Customers (Full Year)	x	x	x	x	
Class B RPP Customers	x	x	x		
1. DVA Rate Rider 1 = disposition of low voltage, SME, Network, Connection, IRM balances					
2. DVA Rate Rider 2 = disposition of Power and Wholesale Market Service Charges (excluding CBR)					
3. If the allocated CBR B amount does not produce a rate rider in one or more rate class, the entire balance is transferred into Account 1580 WMS control account					

WMPs are charged DVA Rate Rider 1 only, which includes account balances for low voltage charges, retail transmission network charges, and retail transmission connection charges.

Class A customers are charged the sum of DVA Rate Rider 1 and DVA Rate Rider 2, the latter of which includes account balances for power and wholesale market service charges excluding CBR.

Transition customers are charged the sum of DVA Rate Rider 1 and DVA Rate Rider 2; and a customer-specific bill adjustment for their portion of the GA and CBR account balances.

Class B, non-RPP customers are charged the sum of DVA Rate Riders 1 and 2; and the GA and CBR Rate Riders.

Class B RPP customers are charged the sum of DVA Rate Riders 1 and 2; and the CBR Rate Rider.

The Group 1 DVAs disposition by customer group is identified in Table 9-3-107, below.

Table 9-3-107: Group 1 DVAs Disposition by Customer Group – Guelph Hydro RZ

Description	Account	Amount
Low Voltage	1550	(40,378)
Smart Meter Entity Charge (Residential and GS<50kW Classes Only)	1551	(23,273)
Retail Transmission Network Charge	1584	231,933
Retail Transmission Connection Charge	1586	25,026
Disposition and Recovery/Refund of Regulatory Balances	1595	138,146
All Customers - DVA Rate Rider 1		**331,454**
Power	1588	227,573
Wholesale Market Service Charge excluding CBR	1580	(3,272,916)
All Customers ex WMPs - DVA Rate Rider 2		**(3,045,343)**
Wholesale Market Service Charge - CBR Class B	1580	452,732
Capacity Based Recovery - Transition Customers	1580	8,396
All Class B Customers ex WMPs - CBR B Rate Rider/Bill Adjustment		**461,128**
Global Adjustment - Non-RPP Class B Customers	1589	316,609
Global Adjustment - Transition Customers	1589	18,241
Class B Non-RPP Customers only - GA Rate Rider/Bill Adjustment		**334,850**
Total (Repayment to)/Recovery from Customers		**(1,917,911)**
Disposition via Rate Rider		(1,944,548)
Global Adjustment - Transition Customers		18,241
Capacity Based Recovery - Transition Customers		8,396

All balances claimed are allocated to the rate classes based on the default cost allocation methodology as identified in the EDDVAR report.

The billing determinants, billing adjustments, and calculation of the rate riders are provided in Tabs 4 through 7 in the DVA Continuity Schedule filed as Attachment 9-5. Alectra Utilities requests disposition of the Guelph Hydro RZ adjusted Group 1 balances, through the rate riders identified in Table 9-3-108, below.

Table 9-3-108: Deferral and Variance Account Riders – Guelph Hydro RZ

Customer Class	Deferral/ Variance Account Rate Rider		Deferral/ Variance Account Rate Rider for Non-WMP		Global Adjustment Rate Rider Non-RPP Class B		CBR B Rate Rider Class B Consumer	
	$/kWh	$/kW	$/kWh	$/kW	$/kWh	$/kW	$/kWh	$/kW
Residential	(0.0017)				0.0012		0.0005	
General Service Less Than 50 kW	(0.0016)				0.0012		0.0005	
General Service 50 To 999 kW		0.0779		(0.6610)	0.0012			0.1809
General Service 1,000 To 4,999 kW		(0.7673)			0.0012			0.2701
Large Use		(0.7384)						
Unmetered Scattered Load	(0.0016)				0.0012		0.0005	
Sentinel Lighting		(0.5871)			—			0.1866
Street Lighting		(0.5792)			0.0012			0.1842

Commodity Accounts Analysis Workform

The Commodity Accounts Analysis Workform for the Guelph Hydro RZ is filed as Attachment 9-21. The Commodity Accounts Analysis Workform assesses the reasonability of Account 1589, RSVA GA and Account 1588, RSVA Power through a calculation of expected principal balances and compares the expected amounts to the amounts reported in the distributor's general ledger. The Commodity Accounts Analysis Workform provides a tool to assess if the principal activity in Accounts 1589 and 1588 for a specific year is reasonable and distributors must explain unreconciled variances greater than +/- 1% of IESO purchases. Distributors are required to submit a Commodity Accounts Analysis Workform for each year that has not previously been approved by the OEB for disposition.

Account 1589

The Commodity Accounts Analysis Workform compares the principal activity in the general ledger for Account 1589 to the expected principal balances based on monthly GA volumes, revenue, and costs.

The principal activity in Account 1589 recorded in 2025 was $2,154,585 as identified in Table 9-3-109 below. The principal activity balance, after known adjustments of $(1,796,102) was $358,483. This is compared to the expected principal balance in Account 1589 of $297,509 calculated in Attachment 9-21, which results in an unreconciled difference of $60,974. This represents 0.43% of Alectra Utilities 2025 IESO purchases in the Guelph Hydro RZ, which is within the OEB's threshold (+/- 1% of IESO purchases).

Table 9-3-109: Commodity Accounts Analysis Workform Summary

Description	Amount
Principal Activity in RSVA(GA)	2,154,585
Add Known Adjustments	(1,796,102)
Adjusted Principal Activity in RSVA(GA)	358,483
Expected Principal Activity in RSVA(GA)	297,509
Variance $	60,974
Total 2025 IESO Purchases	14,266,330
Absolute Variance as a % of IESO Purchases	**0.43 %**

Account 1588

The Commodity Accounts Analysis Workform also includes a reasonability test for Account 1588, RSVA Power, and compares the annual Account 1588 variance to the Cost of Power purchases in the respective year.

The transactions in Account 1588 recorded in 2025 was $(1,091,241) as identified in Table 9-3-110 below. The transactions, after principal adjustments of $1,301,241 was $210,000. This is compared to the power purchased of $128,399,874, which represents 0.16% of purchases, which is within the OEB's threshold.

Table 9-3-110: Account 1588 Power Summary

Description	Amount
Principal Activity in RSVA(Power)	(1,091,241)
Add Known Adjustments	1,301,241
Total Activity in 2025	210,000
Account 4705 - Power Purchased	128,399,874
Absolute Variance as a % of Power Purchased	**0.16 %**

Attachment 9-17

Commodity Accounts Analysis Workform HRZ

Please see live Excel version

Attachment 9-18

Commodity Accounts Analysis Workform BRZ

Please see live Excel version

Attachment 9-19

Commodity Accounts Analysis Workform PRZ

Please see live Excel version

Attachment 9-20

Commodity Accounts Analysis Workform ERZ

Please see live Excel version

Attachment 9-21

Commodity Accounts Analysis Workform GRZ

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