ENBRIDGE INC.

CONSOLIDATED FINANCIAL STATEMENTS

December 31, 2025

MANAGEMENT'S REPORT

TO THE SHAREHOLDERS OF ENBRIDGE INC.

Financial Reporting
Management of Enbridge Inc. (the Company) is responsible for the accompanying consolidated financial statements and all related financial information contained in the annual report, including Management's Discussion and Analysis. The consolidated financial statements have been prepared in accordance with generally accepted accounting principles in the United States of America (US GAAP) and necessarily include amounts that reflect management's judgment and best estimates.

The Board of Directors (the Board) and its committees are responsible for all aspects related to governance of the Company. The Audit, Finance & Risk Committee (the AFRC) of the Board, composed of directors who are unrelated and independent, has a specific responsibility to oversee management's efforts to fulfil its responsibilities for financial reporting and internal controls related thereto. The AFRC meets with management, internal auditors and Independent Registered Public Accounting Firm auditors to review the consolidated financial statements and the internal controls as they relate to financial reporting. The AFRC reports its findings to the Board for its consideration in approving the consolidated financial statements for issuance to the shareholders. The internal auditors and Independent Registered Public Accounting Firm auditors have unrestricted access to the AFRC.

Internal Control over Financial Reporting
Management is also responsible for establishing and maintaining adequate internal control over financial reporting. The Company's internal control over financial reporting includes policies and procedures to facilitate the preparation of relevant, reliable and timely information, to prepare consolidated financial statements for external reporting purposes in accordance with US GAAP and to provide reasonable assurance that assets are safeguarded.

Management assessed the effectiveness of the Company's internal control over financial reporting as at December 31, 2025, based on the framework established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, management concluded that the Company maintained effective internal control over financial reporting as at December 31, 2025.

PricewaterhouseCoopers LLP, an Independent Registered Public Accounting Firm appointed by the shareholders of the Company, have conducted an audit of the consolidated financial statements of the Company and its internal control over financial reporting in accordance with the standards of the Public Company Accounting Oversight Board (United States) and have issued an unqualified audit report, which is accompanying the consolidated financial statements.

/s/ Gregory L. Ebel
Gregory L. Ebel
President and Chief Executive Officer

/s/ Patrick R. Murray
Patrick R. Murray
Executive Vice President and Chief Financial Officer

February 13, 2026

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholders of Enbridge Inc.

Opinions on the Financial Statements and Internal Control over Financial Reporting

We have audited the accompanying consolidated statements of financial position of Enbridge Inc. and its subsidiaries (the Company) as of December 31, 2025 and 2024, and the related consolidated statements of earnings, of comprehensive income, of changes in equity and of cash flows for each of the three years in the period ended December 31, 2025, including the related notes (collectively referred to as the consolidated financial statements). We also have audited the Company's internal control over financial reporting as of December 31, 2025, based on criteria established in *Internal Control – Integrated Framework* (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2025 and 2024, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2025 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2025, based on criteria established in *Internal Control – Integrated Framework* (2013) issued by the COSO.

Basis for Opinions

The Company's management is responsible for these consolidated financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express opinions on the Company's consolidated financial statements and on the Company's internal control over financial reporting based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud, and whether effective internal control over financial reporting was maintained in all material respects.

Our audits of the consolidated financial statements included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis,

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evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

Definition and Limitations of Internal Control over Financial Reporting

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Critical Audit Matters

The critical audit matter communicated below is a matter arising from the current period audit of the consolidated financial statements that was communicated or required to be communicated to the audit committee and that (i) relates to accounts or disclosures that are material to the consolidated financial statements and (ii) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the consolidated financial statements, taken as a whole, and we are not, by communicating the critical audit matter below, providing a separate opinion on the critical audit matter or on the accounts or disclosures to which it relates.

Quantitative goodwill impairment assessment for the Gas Transmission (GT) and Gas Distribution and Storage (GDS) reporting units

As described in Notes 2 and 15 to the consolidated financial statements, the Company's goodwill balance was $35,284 million as of December 31, 2025, which includes goodwill balances of $17,531 million and $8,721 million related to the GT and GDS reporting units, respectively. As disclosed by management, an annual goodwill impairment assessment is performed at the reporting unit level as of April 1 of each year, or more frequently if events or circumstances indicate that the carrying value of goodwill may be impaired. Management has the option to first assess qualitative factors to determine whether it is necessary to perform the quantitative goodwill impairment assessment. Management performed a quantitative goodwill impairment assessment for the GT and GDS reporting units. The quantitative goodwill impairment assessment involves determining the fair value of the Company's reporting units and comparing those values to the carrying value of each reporting unit. If the carrying value of a reporting unit, including allocated goodwill, exceeds its fair value, goodwill impairment is measured at the amount by which the reporting unit’s carrying value exceeds its fair value. The fair value of the reporting units is estimated using either a discounted cash flow technique or a combination of discounted cash flow and earnings multiples techniques. The determination of fair value using the discounted cash flow technique requires the use of estimates and assumptions related to discount rates, projected operating income, expected future capital expenditures, as well as terminal value growth rate for the GT reporting unit, and projected regulatory rate base and rate base multiple for the GDS reporting unit. The determination of fair value using the earnings multiples technique requires assumptions to be made in relation to maintainable earnings and earnings multiples. Following management’s assessment, no impairment charges were recognized.

The principal considerations for our determination that performing procedures relating to the quantitative goodwill impairment assessment for the GT and GDS reporting units is a critical audit matter are the significant judgments required by management when developing such assumptions as discount rate, projected operating income and earnings multiples used to estimate the fair value of the GT reporting unit and projected regulatory rate base and rate base multiple used to estimate the fair value of the GDS reporting unit as of April 1, 2025. This led to a high degree of auditor judgment, effort and subjectivity in performing procedures to evaluate the reasonableness of these assumptions used in the quantitative goodwill impairment assessment. In addition, the audit effort involved the use of professionals with specialized skill and knowledge.

Addressing the matter involved performing procedures and evaluating audit evidence in connection with forming our overall opinion on the consolidated financial statements. These procedures included testing the effectiveness of controls relating to management’s quantitative goodwill impairment assessment, including controls over the determination of the fair value estimates of the GT and GDS reporting units. These procedures also included, among others, testing management’s process for developing the fair value estimates of the GT and GDS reporting units. Testing management’s process for developing the fair value estimates included evaluating the appropriateness of the discounted cash flow and the earnings multiples models; testing the completeness and accuracy of underlying data used in the models; and evaluating the reasonableness of projected operating income and the projected regulatory rate base by considering the current and past performance of the Company’s reporting units, external industry data and evidence obtained in other areas of the audit, as applicable. Professionals with specialized skill and knowledge assisted in evaluating the appropriateness of management’s discounted cash flow and earnings multiples models and the reasonableness of the discount rate, earnings multiples and rate base multiple used in the models, as applicable.

/s/PricewaterhouseCoopers LLP

Chartered Professional Accountants

Calgary, Canada
February 13, 2026

We have served as the Company’s auditor since 1949.

ENBRIDGE INC.
CONSOLIDATED STATEMENTS OF EARNINGS

Year ended December 31,	**2025**	2024	2023
(millions of Canadian dollars, except per share amounts)			
Operating revenues			
Commodity sales	**35,181**	27,018	18,981
Gas distribution sales	**9,769**	6,802	5,442
Transportation and other services	**20,244**	19,653	19,226
Total operating revenues *(Note 4)*	**65,194**	53,473	43,649
Operating expenses			
Commodity costs	**34,358**	26,556	18,526
Gas distribution costs	**3,678**	2,484	2,840
Operating and administrative	**9,969**	9,427	8,600
Depreciation and amortization	**5,661**	5,167	4,613
Impairment of long-lived assets	**570**	190	419
Total operating expenses	**54,236**	43,824	34,998
Operating income	**10,958**	9,649	8,651
Income from equity investments *(Note 13)*	**2,224**	2,304	1,816
Gain on disposition of equity investments *(Note 13)*	**—**	1,091	—
Other income/(expense) *(Note 27)*	**1,634**	(1,326)	1,224
Interest expense *(Note 17)*	**(5,023)**	(4,419)	(3,812)
Earnings before income taxes	**9,793**	7,299	7,879
Income tax expense *(Note 24)*	**(2,004)**	(1,668)	(1,821)
Earnings	**7,789**	5,631	6,058
(Earnings)/loss attributable to noncontrolling interests and redeemable noncontrolling interest	**(298)**	(190)	133
Earnings attributable to controlling interests	**7,491**	5,441	6,191
Preference share dividends	**(419)**	(388)	(352)
Earnings attributable to common shareholders	**7,072**	5,053	5,839
Earnings per common share attributable to common shareholders *(Note 6)*	**3.23**	2.34	2.84
Diluted earnings per common share attributable to common shareholders *(Note 6)*	**3.22**	2.34	2.84

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

ENBRIDGE INC.
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Year ended December 31,	**2025**	2024	2023
(millions of Canadian dollars)			
Earnings	**7,789**	5,631	6,058
Other comprehensive income/(loss), net of tax			
Change in unrealized gain on cash flow hedges	**28**	73	220
Gain/(loss) on net investment hedges *(Note 23)*	**419**	(1,305)	409
Other comprehensive income/(loss) from equity investees and other investments	**24**	(10)	6
Excluded components of fair value hedges	**14**	9	12
Reclassification to earnings of loss on cash flow hedges	**27**	23	14
Reclassification to earnings of pension and other postretirement benefits (OPEB) amounts	**(30)**	(16)	(18)
Reclassification of actuarial gain on pension and OPEB from regulatory assets	**38**	—	—
Actuarial gain/(loss) on pension and OPEB	**126**	248	(130)
Foreign currency translation adjustments	**(3,134)**	5,895	(1,728)
Other comprehensive income/(loss), net of tax	**(2,488)**	4,917	(1,215)
Comprehensive income	**5,301**	10,548	4,843
Comprehensive (income)/loss attributable to noncontrolling interests and redeemable noncontrolling interest	**(244)**	(295)	131
Comprehensive income attributable to controlling interests	**5,057**	10,253	4,974
Preference share dividends	**(419)**	(388)	(352)
Comprehensive income attributable to common shareholders	**4,638**	9,865	4,622

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

ENBRIDGE INC.
CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

Year ended December 31,	**2025**	2024	2023
(millions of Canadian dollars, except per share amounts)			
Preference shares *(Note 20)*			
Balance at beginning and end of year	**6,818**	6,818	6,818
Common shares *(Note 20)*			
Balance at beginning of year	**71,738**	69,180	64,760
Shares issued, net of issue costs and tax	**—**	2,489	4,485
Shares issued on exercise of stock options	**89**	39	3
Shares issued on vesting of restricted stock units (RSU)	**49**	30	12
Share repurchases at stated value	**—**	—	(80)
Balance at end of year	**71,876**	71,738	69,180
Additional paid-in capital			
Balance at beginning of year	**275**	268	275
Stock-based compensation	**113**	98	71
Stock options exercised	**(61)**	(39)	(3)
Vested RSUs	**(85)**	(52)	(20)
Purchase of noncontrolling interests	**—**	—	(28)
Other	**—**	—	(27)
Balance at end of year	**242**	275	268
Deficit			
Balance at beginning of year	**(20,046)**	(17,115)	(15,486)
Earnings attributable to controlling interests	**7,491**	5,441	6,191
Preference share dividends	**(419)**	(388)	(352)
Common share dividends declared	**(8,282)**	(7,984)	(7,423)
Share repurchases in excess of stated value	**—**	—	(45)
Redemption value adjustment attributable to redeemable noncontrolling interest *(Note 19)*	**(28)**	—	—
Balance at end of year	**(21,284)**	(20,046)	(17,115)
Accumulated other comprehensive income *(Note 22)*			
Balance at beginning of year	**7,115**	2,303	3,520
Other comprehensive income/(loss) attributable to common shareholders, net of tax	**(2,434)**	4,812	(1,217)
Balance at end of year	**4,681**	7,115	2,303
Total Enbridge Inc. shareholders' equity	**62,333**	65,900	61,454
Noncontrolling interests *(Note 19)*			
Balance at beginning of year	**2,993**	3,029	3,511
Earnings/(loss) attributable to noncontrolling interests	**270**	190	(133)
Other comprehensive income/(loss) attributable to noncontrolling interests, net of tax			
Change in unrealized gain on cash flow hedges	**—**	9	35
Foreign currency translation adjustments	**(54)**	96	(33)
	(54)	105	2
Comprehensive income/(loss) attributable to noncontrolling interests	**216**	295	(131)
Distributions	**(360)**	(333)	(363)
Contributions	**10**	4	11
Purchase of noncontrolling interests	**—**	(2)	2
Other	**(4)**	—	(1)
Balance at end of year	**2,855**	2,993	3,029
Total equity	**65,188**	68,893	64,483
Dividends paid per common share	**3.77**	3.66	3.55

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

ENBRIDGE INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS

Year ended December 31,	**2025**	2024	2023
(millions of Canadian dollars)			
Operating activities			
Earnings	**7,789**	5,631	6,058
Adjustments to reconcile earnings to net cash provided by operating activities:			
Depreciation and amortization	**5,661**	5,167	4,613
Deferred income tax expense *(Note 24)*	**1,025**	719	1,420
Unrealized derivative fair value (gain)/loss, net	**(1,334)**	2,082	(1,180)
Income from equity investments *(Note 13)*	**(2,224)**	(2,304)	(1,816)
Distributions from equity investments	**2,066**	2,121	1,998
Impairment of long-lived assets	**570**	190	419
Gain on disposition of equity investments *(Note 13)*	**—**	(1,091)	—
Other	**122**	218	378
Changes in operating assets and liabilities *(Note 28)*	**(1,405)**	(133)	2,311
Net cash provided by operating activities	**12,270**	12,600	14,201
Investing activities			
Capital expenditures	**(8,973)**	(6,711)	(4,654)
Long-term, restricted and other investments	**(2,322)**	(3,416)	(1,276)
Distributions from equity investments in excess of cumulative earnings	**681**	785	1,151
Additions to intangible assets	**(192)**	(219)	(222)
Acquisitions	**—**	(13,472)	(954)
Proceeds from disposition of equity investments	**349**	2,724	—
Net change in affiliate loans	**—**	2	(27)
Other	**(46)**	(56)	(61)
Net cash used in investing activities	**(10,503)**	(20,363)	(6,043)
Financing activities			
Net change in short-term borrowings	**501**	129	(1,596)
Net change in commercial paper and credit facility draws	**1,296**	6,549	(8,157)
Debenture and term note issues, net of issue costs	**10,956**	9,546	15,377
Debenture and term note repayments	**(6,849)**	(6,633)	(4,819)
Contributions from noncontrolling interests	**10**	4	11
Distributions to noncontrolling interests	**(360)**	(333)	(363)
Proceeds from investment by redeemable noncontrolling interest in subsidiary, net of transaction costs	**712**	—	—
Contributions from redeemable noncontrolling interest	**6**	—	—
Distributions to redeemable noncontrolling interest	**(17)**	—	—
Common shares issued, net of issue costs	**28**	2,485	4,450
Common shares repurchased	**—**	—	(125)
Preference share dividends	**(419)**	(387)	(352)
Common share dividends	**(8,220)**	(7,875)	(7,276)
Net change in affiliate loans	**41**	99	71
Other	**(85)**	(40)	(85)
Net cash (used in)/provided by financing activities	**(2,400)**	3,544	(2,864)
Effect of translation of foreign denominated cash and cash equivalents and restricted cash	**(47)**	234	(216)
Net change in cash and cash equivalents and restricted cash	**(680)**	(3,985)	5,078
Cash and cash equivalents and restricted cash at beginning of period[1]	**2,000**	5,985	907
Cash and cash equivalents and restricted cash at end of period[1]	**1,320**	2,000	5,985
Supplementary cash flow information			
Cash paid for interest, net of amount capitalized	**4,924**	4,134	3,380
Property, plant and equipment and intangible assets non-cash accruals	**1,390**	1,251	813

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

1 *As at December 31, 2025, long-term restricted cash of $143 million (2024 - $105 million and 2023 - nil, respectively) was included in Restricted long-term investments and cash in the Consolidated Statements of Financial Position.*

ENBRIDGE INC.
CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

December 31,	**2025**	2024
(millions of Canadian dollars; number of shares in millions)		
Assets		
Current assets		
Cash and cash equivalents	**1,094**	1,803
Restricted cash	**83**	92
Trade receivables and unbilled revenues	**7,081**	6,920
Other current assets *(Note 9)*	**3,230**	2,770
Accounts receivable from affiliates	**86**	90
Inventory *(Note 10)*	**1,621**	1,488
	13,195	13,163
Property, plant and equipment, net *(Note 11)*	**131,598**	131,104
Long-term investments *(Note 13)*	**21,264**	20,691
Restricted long-term investments and cash	**1,293**	998
Deferred amounts and other assets	**11,149**	11,034
Intangible assets, net *(Note 14)*	**3,991**	4,587
Goodwill *(Note 15)*	**35,284**	36,600
Deferred income taxes *(Note 24)*	**701**	796
Total assets	**218,475**	218,973
Liabilities and equity		
Current liabilities		
Short-term borrowings *(Note 17)*	**1,030**	529
Trade payables and accrued liabilities	**7,555**	7,060
Other current liabilities *(Note 16)*	**6,174**	7,241
Accounts payable to affiliates	**38**	22
Interest payable	**1,176**	1,231
Current portion of long-term debt *(Note 17)*	**5,031**	7,729
	21,004	23,812
Long-term debt *(Note 17)*	**98,963**	93,414
Other long-term liabilities	**12,302**	13,258
Deferred income taxes *(Note 24)*	**20,282**	19,596
	152,551	150,080
Commitments and contingencies *(Note 30)*		
Redeemable noncontrolling interest *(Note 19)*	**736**	—
Equity		
Share capital *(Note 20)*		
Preference shares	**6,818**	6,818
Common shares *(2,182 and 2,178 outstanding at December 31, 2025 and 2024, respectively)*	**71,876**	71,738
Additional paid-in capital	**242**	275
Deficit	**(21,284)**	(20,046)
Accumulated other comprehensive income *(Note 22)*	**4,681**	7,115
Total Enbridge Inc. shareholders' equity	**62,333**	65,900
Noncontrolling interests *(Note 19)*	**2,855**	2,993
	65,188	68,893
Total liabilities and equity	**218,475**	218,973

Variable Interest Entities (VIEs) *(Note 12)*

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

Approved by the Board of Directors:

/s/ Steven W. Williams	**/s/ Teresa S. Madden**
Steven W. Williams	Teresa S. Madden
Chair	Director

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS
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1. BUSINESS OVERVIEW

The terms "we", "our", "us" and "Enbridge" as used in this report refer collectively to Enbridge Inc. and its subsidiaries unless the context suggests otherwise. These terms are used for convenience only and are not intended as a precise description of any separate legal entity within Enbridge.

Enbridge is a publicly traded energy transportation and distribution company. We conduct our business through four business segments: Liquids Pipelines, Gas Transmission, Gas Distribution and Storage, and Renewable Power Generation. These reporting segments are strategic business units established by senior management to facilitate the achievement of our long-term objectives, to aid in resource allocation decisions and to assess operational performance.

LIQUIDS PIPELINES
Liquids Pipelines consists of pipelines and terminals in Canada and the United States (US) that transport, store and export various grades of crude oil and other liquid hydrocarbons, including the Mainline System, Regional Oil Sands System, Gulf Coast and Mid-Continent Systems, and Other. Our Canadian and US crude oil marketing businesses are also included in this segment. These businesses provide energy marketing services to customers and undertake physical commodity marketing activity and logistical services to manage our volume commitments on various pipeline systems.

GAS TRANSMISSION
Gas Transmission consists of our investments in natural gas pipelines and gathering, processing and storage facilities in Canada and the US, including US Gas Transmission, Canadian Gas Transmission, and Other. This segment also includes investments in renewable natural gas (RNG) facilities. On July 2, 2025, Stonlasec8 Indigenous Investments Limited Partnership (the First Nations Partnership), an entity representing 38 First Nations in British Columbia (BC), invested in our Westcoast Energy Inc. (Westcoast) BC natural gas pipeline system. As a result of this investment, the First Nations Partnership holds a redeemable noncontrolling interest in these assets *(Note 8)*.

GAS DISTRIBUTION AND STORAGE
Gas Distribution and Storage consists of our rate-regulated natural gas utility operations in Canada and the US, which service residential, commercial and industrial customers in Ontario, Québec, Ohio, North Carolina, Utah, Wyoming and Idaho. This segment also includes Wexpro Company (Wexpro), which develops and produces natural gas reserves for our gas distribution operations in Utah, Wyoming and Idaho.

RENEWABLE POWER GENERATION
Renewable Power Generation consists primarily of investments in wind and solar power generation facilities, as well as an equity interest in geothermal power facilities. In North America, our assets are primarily located in the provinces of Alberta, Ontario and Québec, and in the states of Colorado, Texas, Indiana, Ohio and West Virginia. We also hold interests in offshore wind facilities in operation, under construction and in active development in the United Kingdom, France and Germany.

ELIMINATIONS AND OTHER
In addition to the segments described above, Eliminations and Other includes operating and administrative costs that are not allocated to business segments, the impact of foreign exchange hedge settlements and the activities of our wholly-owned captive insurance subsidiary. The principal activity of our captive insurance subsidiary is providing insurance and reinsurance coverage for certain insurable property and casualty risk exposures of our operating subsidiaries and certain equity investments. Eliminations and Other also includes new business development activities, corporate investments and our natural gas and power marketing businesses.

Enbridge's chief operating decision maker (CODM) is the President and Chief Executive Officer. The CODM uses earnings before interest, income taxes and depreciation and amortization (EBITDA), disaggregated by line of business, to assess segment performance and to set targets predominantly in the annual and long-term budgeting and forecasting process. Budget-to-actual and actual-to-actual variances in EBITDA are considered when making decisions about the allocation of resources to the segments and to meet our strategic priorities. Refer to *Note 5 - Segmented Information* for a reconciliation of EBITDA to earnings before income taxes.

2. SIGNIFICANT ACCOUNTING POLICIES

These consolidated financial statements are prepared in accordance with accounting principles generally accepted in the United States of America (US GAAP). Amounts are stated in Canadian dollars unless otherwise noted. As a Securities and Exchange Commission (SEC) registrant, we are permitted to use US GAAP for the purposes of meeting both our Canadian and US continuous disclosure requirements.

BASIS OF PRESENTATION AND USE OF ESTIMATES

The preparation of financial statements in conformity with US GAAP requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, as well as the disclosure of contingent assets and liabilities in the consolidated financial statements. Significant estimates and assumptions used in the preparation of the consolidated financial statements include, but are not limited to: variable consideration included in revenue *(Note 4);* carrying values of regulatory assets and liabilities *(Note 7)*; purchase price allocations *(Note 8)*; unbilled revenues; expected credit losses; depreciation rates and carrying value of property, plant and equipment *(Note 11)*; amortization rates and carrying value of intangible assets *(Note 14)*; measurement of goodwill *(Note 15)*; fair value of asset retirement obligations (ARO) *(Note 18)*; valuation of stock-based compensation *(Note 21)*; fair value of financial instruments *(Note 23)*; provisions for income taxes *(Note 24)*; assumptions used to measure retirement benefits and OPEB *(Note 25)*; commitments and contingencies *(Note 30)*; and estimates of losses related to environmental remediation obligations *(Note 30)*. Actual results could differ from these estimates.

Certain comparative figures in our consolidated financial statements have been reclassified to conform to the current year's presentation.

PRINCIPLES OF CONSOLIDATION

The consolidated financial statements include our accounts and the accounts of our subsidiaries and VIEs for which we are the primary beneficiary. A VIE is a legal entity that does not have sufficient equity at risk to finance its activities without additional subordinated financial support or is structured such that equity investors lack the ability to make significant decisions relating to the entity's operations through voting rights or do not substantively participate in the gains and losses of the entity. Upon inception of a contractual agreement, we perform an assessment to determine whether the arrangement contains a variable interest in a legal entity and whether that legal entity is a VIE. The primary beneficiary has both the power to direct the activities of the VIE that most significantly impact the entity's economic performance and the obligation to absorb losses, or the right to receive benefits from, the VIE that could potentially be significant to the VIE. Where we conclude that we are the primary beneficiary of a VIE, we consolidate the accounts of that VIE. We assess all variable interests in the entity and use our judgment when determining if we are the primary beneficiary. Other qualitative factors that are considered include decision-making responsibilities, the VIE capital structure, risk and rewards sharing, contractual agreements with the VIE, voting rights and level of involvement of other parties. We assess the primary beneficiary determination for a VIE on an ongoing basis if there are changes in the facts and circumstances related to a VIE. If an entity is determined to not be a VIE, the voting interest entity model is applied, where an investor holding the majority voting rights consolidates the entity. The consolidated financial statements also include the accounts of any limited partnerships where we represent the general partner and, based on all facts and circumstances, control such limited partnerships, unless the limited partner has substantive participating rights or substantive kick-out rights. For certain investments where we retain an undivided interest in assets and liabilities, we record our proportionate share of assets, liabilities, revenues and expenses.

All intercompany accounts and transactions are eliminated upon consolidation. Ownership interests in subsidiaries represented by other parties that do not control the entity are presented in the consolidated financial statements as activities and balances attributable to noncontrolling interests (NCI). Investments and entities over which we exercise significant influence are accounted for using the equity method.

REGULATION

Certain of our businesses are subject to regulation by various authorities including, but not limited to, the Canada Energy Regulator (CER), the Federal Energy Regulatory Commission (FERC), the Alberta Energy Regulator, the British Columbia (BC) Energy Regulator, the Ontario Energy Board (OEB), the Québec Régie de l'énergie, the Public Utilities Commission of Ohio (Ohio Commission), the North Carolina Utilities Commission (North Carolina Commission), the Utah Public Service Commission (Utah Commission), the Wyoming Public Service Commission (Wyoming Commission), and the Idaho Public Utilities Commission (Idaho Commission). Regulatory bodies exercise statutory authority over matters such as construction, rates and ratemaking, and agreements with customers. To recognize the economic effects of the actions of the regulator, the timing of recognition of certain revenues and expenses in these operations may differ from that otherwise expected under US GAAP for non-rate-regulated entities.

Regulatory assets represent amounts that are expected to be recovered from customers in future periods through rates. Regulatory liabilities represent amounts that are expected to be refunded to customers in future periods through rates, amounts collected from customers in advance of costs being incurred, or to be paid to cover future abandonment costs and for future removal and site restoration costs as approved by the regulator. If there are changes in our assessment of the probability of recovery for a regulatory asset, we reduce its carrying amount to the balance that we expect to recover from customers in future periods through rates. If a regulator later excludes from allowable costs all or a part of costs that were capitalized as a regulatory asset, we reduce the carrying amount of the asset by the excluded amounts. The recognition of regulatory assets and liabilities is based on the actions, or expected future actions, of the regulator. To the extent that the regulator's actions differ from our expectations, the timing and amount of recovery or settlement of regulatory balances could differ significantly from those recorded. In the absence of rate regulation, we would generally not recognize regulatory assets or liabilities and the earnings impact would be recorded in the period the expenses are incurred or revenues are earned. A regulatory asset or liability is recognized in respect of deferred income taxes when it is expected the amounts will be recovered or settled through future regulator-approved rates. We believe that the recovery of our regulatory assets as at December 31, 2025 is probable over the periods described in *Note 7 - Regulatory Matters*.

During the fourth quarter of 2023, Southern Lights Pipeline completed an open season to negotiate new transportation service agreements. We did not renew the agreements under a cost-of-service toll methodology, therefore Southern Lights Pipeline was no longer subject to rate-regulated accounting. As a result, the related regulatory liabilities, regulatory tax assets and associated regulatory deferred tax liabilities were derecognized in 2023.

We collect and set aside funds to cover future pipeline abandonment costs for all CER-regulated pipelines in accordance with the Land Matters Consultation Initiative (LMCI), to fund future pipeline decommissioning costs in the state of Minnesota and to satisfy retirement obligations as Wexpro properties are abandoned. The funds collected are held in trusts in accordance with applicable regulations. The funds collected from customers are reported within Operating revenues in the Consolidated Statements of Earnings and Restricted long-term investments and cash in the Consolidated Statements of Financial Position. Concurrently, for LMCI, we reflect the future abandonment cost as an increase to Operating and administrative expense in the Consolidated Statements of Earnings and Other long-term liabilities in the Consolidated Statements of Financial Position.

An allowance for funds used during construction (AFUDC) is included in the cost of property, plant and equipment and is depreciated over future periods as part of the total cost of the related asset. AFUDC includes both an interest component and, if approved by the regulator, a cost of equity component, which are both capitalized based on rates set out in a regulatory agreement. The corresponding impact on earnings is included in Interest expense for the interest component and Other income/(expense) for the equity component. In the absence of rate regulation, we would capitalize interest using a capitalization rate based on our cost of borrowing, whereas the capitalized equity component, the corresponding earnings during the construction phase and the subsequent depreciation relating to the equity component would not be recognized. The equity component of AFUDC is included as a non-cash reconciling item to earnings within Cash Flows from Operating Activities in the Consolidated Statements of Cash Flows.

Under the pool method prescribed by certain regulators, it is not possible to identify the carrying value of the equity component of AFUDC or its effect on depreciation. Similarly, gains and losses on the retirement of certain specific fixed assets in any given year cannot be identified or quantified.

With the approval of regulators, certain operations capitalize a portion of specified operating costs. These operations are authorized to charge depreciation and earn a return on the net book value of such capitalized costs in future years. In the absence of rate regulation, a portion of such operating costs would be charged to earnings in the year incurred.

For certain regulated operations to which US GAAP guidance for phase-in plans applies, negotiated depreciation rates recovered in transportation tolls may be less than the depreciation expense calculated in accordance with US GAAP in early years of long-term contracts but recovered in future periods when tolls exceed depreciation. Depreciation expense on such assets is recorded in accordance with US GAAP and no regulatory asset is recorded.

REVENUE RECOGNITION

For businesses that are not rate-regulated, revenues are recorded when products have been delivered or services have been performed, the amount of revenue can be reliably measured and collectability is reasonably assured. Customer creditworthiness is assessed prior to agreement signing and throughout the contract duration. Certain revenues from our liquids and natural gas pipeline businesses are recognized under the terms of committed delivery contracts, rather than the cash tolls received.

Long-term take-or-pay contracts, under which shippers are obligated to pay fixed amounts ratably over the contract period regardless of volumes shipped, may contain make-up rights. Make-up rights are earned by shippers when minimum volume commitments are not utilized during the period but under certain circumstances can be used to offset overages in future periods, subject to expiry. We recognize revenues associated with make-up rights at the earlier of when the make-up volume is shipped, the make-up right expires, or when it is determined that the likelihood that the shipper will utilize the make-up right is remote. We also have long-term contracts where the revenue profile does not align with the cash receipt schedule, resulting in the recognition of deferred revenue.

Certain offshore pipeline transportation contracts require us to provide transportation services for the life of the underlying producing fields. Under these arrangements, shippers pay us a fixed monthly toll for a defined period of time which may be shorter than the estimated reserve life of the underlying producing fields, resulting in a contract period which extends past the period of cash collection. Fixed monthly toll revenues are recognized ratably over the committed volume made available to shippers throughout the contract period, regardless of when cash is received.

For rate-regulated businesses, revenues are recognized in a manner that is consistent with the underlying agreements as approved by the regulators. Natural gas utility revenues are generally recorded based on regular meter readings and estimates of customer usage from the last meter reading to the end of the reporting period. Estimates are based on historical consumption patterns and heating degree days experienced. Heating degree days is a measure of coldness that is indicative of volumetric requirements for natural gas utilized for heating purposes in our distribution franchise areas.

Certain of our US gas utilities have a revenue decoupling mechanism, referred to as a Customer Usage Tracker (CUT) or Conservation Enabling Tariff (CET), which allows for the collection of an allowed monthly revenue per customer and promotes energy conservation. Under the mechanism, non-gas revenues are decoupled from the temperature-adjusted usage per customer. The difference between actual revenue and the allowed monthly revenue per customer is recorded as a regulatory asset or liability and recovered from, or refunded to, customers through periodic rate adjustments.

Amounts deferred under the CUT or CET arise due to specific arrangements with the regulators rather than customers and represent alternative revenue programs. Revenue from alternative revenue programs is recorded within Operating revenues in the Consolidated Statements of Earnings in the month the related adjustments are deferred and is presented as Other revenues not from contracts with customers when disaggregated in *Note 4 - Revenue*.

Our crude oil, natural gas and power marketing businesses enter into commodity purchase and sale arrangements that are recorded on a gross basis as we are acting as the principal in the transactions.

No non-affiliated customer exceeded 10.0% of our third-party revenues for the years ended December 31, 2025, 2024 and 2023.

DERIVATIVE INSTRUMENTS AND HEDGING

Non-qualifying Derivatives

Non-qualifying derivative instruments are used primarily to mitigate foreign exchange, interest rate and commodity price earnings exposure. Non-qualifying derivatives are measured at fair value with changes in fair value recognized in earnings in Commodity sales, Transportation and other services revenues, Commodity costs, Operating and administrative expense, Other income/(expense) and Interest expense.

Derivatives in Qualifying Hedging Relationships

We use derivative financial instruments to manage our exposure to changes in commodity prices, foreign exchange rates and interest rates. Hedge accounting is optional and requires us to document the hedging relationship and test the hedging item's effectiveness in offsetting changes in fair values or cash flows of the underlying hedged item on an ongoing basis. We present the earnings effects of hedging items with the hedged transaction. Derivatives in qualifying hedging relationships are categorized as cash flow hedges, fair value hedges or net investment hedges.

Cash Flow Hedges

We may use cash flow hedges to manage our exposure to changes in commodity prices, foreign exchange rates and interest rates. The change in the fair value of a cash flow hedging instrument is recorded in Other comprehensive income/(loss) (OCI) and is reclassified to earnings when the hedged item impacts earnings.

If a derivative instrument designated as a cash flow hedge ceases to be effective or is terminated, hedge accounting is discontinued and the gain or loss at that date is deferred in OCI and recognized in earnings concurrently with the related transaction. If an anticipated hedged transaction is no longer probable, the gain or loss is recognized immediately in earnings. Subsequent gains and losses from derivative instruments for which hedge accounting has been discontinued are recognized in earnings in the period in which they occur.

Fair Value Hedges
We may use fair value hedges to hedge the fair value of debt instruments. The change in the fair value of the hedging instrument is recorded in earnings with changes in the fair value of the hedged risk of the asset or liability that is designated as part of the hedging relationship. If a fair value hedge is discontinued or ceases to be effective, the hedged risk of the asset or liability ceases to be remeasured at fair value and the cumulative fair value adjustment to the carrying value of the hedged item is recognized in earnings over the remaining life of the hedged item.

Net Investment Hedges
Gains and losses arising from the translation of our net investment in foreign operations from their functional currencies to Enbridge's Canadian dollar presentation currency are included in cumulative translation adjustments (CTA), a component of OCI. We currently have designated a portion of our US dollar-denominated debt, as well as a portfolio of foreign exchange forward contracts in prior periods, as a hedge of our net investment in US dollar-denominated investments and subsidiaries. As a result, the change in fair value of the foreign currency derivatives, as well as the translation of US dollar-denominated debt, are reflected in OCI. Amounts recognized previously in Accumulated other comprehensive income/(loss) (AOCI) are reclassified to earnings when there is a reduction of the hedged net investment resulting from the disposal of a foreign operation.

Classification of Derivatives
We recognize the fair value of derivative instruments in the Consolidated Statements of Financial Position as current and non-current assets or liabilities depending on the timing of settlements and the resulting cash flows associated with the instruments. Fair value amounts related to cash flows occurring beyond one year are classified as non-current.

Cash inflows and outflows related to derivative instruments are classified as Cash Flows from Operating and Financing Activities in the Consolidated Statements of Cash Flows.

Balance Sheet Offset
Assets and liabilities arising from derivative instruments may be offset in the Consolidated Statements of Financial Position when we have the legal right and intention to settle them on a net basis.

TRANSACTION COSTS
Transaction costs are incremental costs directly related to the acquisition of a financial asset or the issuance of a financial liability. We incur transaction costs primarily from the issuance of debt and account for these costs as a reduction to Long-term debt in the Consolidated Statements of Financial Position. These costs are amortized using the effective interest rate method over the term of the related debt instrument and are recorded in Interest expense.

EQUITY INVESTMENTS
Equity investments over which we exercise significant influence, but do not have controlling financial interests, are accounted for using the equity method. These investments are initially measured at cost and are adjusted for our proportionate share of undistributed equity earnings or loss. Our equity investments are increased for contributions made to, and decreased for distributions received from, the investee. To the extent an equity investee undertakes activities necessary to commence its planned principal operations, we capitalize interest costs associated with the investment during such period.

RESTRICTED LONG-TERM INVESTMENTS AND CASH
Long-term investments and cash that are restricted as to withdrawal or usage, for the purposes of funding pipeline abandonment in accordance with the CER's LMCI, to cover future pipeline decommissioning costs in the state of Minnesota, and to satisfy retirement obligations as Wexpro properties are abandoned, are presented as Restricted long-term investments and cash in the Consolidated Statements of Financial Position.

Cash and cash equivalents that are restricted as to withdrawal or usage for the purposes of the CER's LMCI or in accordance with specific commercial and debt arrangements are presented as Restricted cash in the Consolidated Statements of Financial Position.

OTHER INVESTMENTS

Generally, we classify equity investments in entities over which we do not exercise significant influence and that do not have readily determinable fair values as other investments measured using the fair value measurement alternative (FVMA). These investments are recorded at cost less impairment, if any, and adjusted for the impact of observable price changes occurring in orderly transactions for an identical or similar investment of the same issuer. Investments in equity securities measured using the FVMA are reviewed for impairment each reporting period and written down to their fair value if objective evidence of impairment is identified.

Equity investments with readily determinable fair values are measured at fair value through earnings. Dividends received from investments in equity securities are recognized in earnings when the right to receive payment is established. Investments in debt securities are classified as available-for-sale and measured at fair value through OCI.

NONCONTROLLING INTERESTS

NCI represent ownership interests attributable to third parties in certain consolidated subsidiaries. The portion of equity not owned by us in such entities is reflected as NCI within the equity section of the Consolidated Statements of Financial Position and, in the case of Redeemable NCI, within the mezzanine equity section of the Consolidated Statements of Financial Position between long-term liabilities and equity.

INCOME TAXES

Income taxes are accounted for using the liability method. Deferred income tax assets and liabilities are recorded based on temporary differences between the tax bases of assets and liabilities and their carrying values for accounting purposes. Deferred income tax assets and liabilities are measured using the tax rate that is expected to apply when the temporary differences reverse. For our regulated operations, a deferred income tax liability or asset is recognized with a corresponding regulatory asset or liability, respectively, to the extent that taxes can be recovered through rates. Any interest and/or penalty incurred related to tax is reflected in Income tax expense.

FOREIGN CURRENCY TRANSACTIONS AND TRANSLATION

Foreign currency transactions are those transactions whose terms are denominated in a currency other than the currency of the primary economic environment in which Enbridge or a reporting subsidiary operates, referred to as the functional currency. Transactions denominated in foreign currencies are translated to the functional currency using the exchange rate prevailing at the date of the transaction. Monetary assets and liabilities denominated in foreign currencies are translated to the functional currency using the exchange rate in effect as at the balance sheet date. Exchange gains and losses resulting from the translation of monetary assets and liabilities are included in earnings in the period in which they arise.

Gains and losses arising from the translation of foreign operations' functional currencies to our Canadian dollar presentation currency are included in the CTA component of AOCI and are recognized in earnings upon sale of the foreign operation. Asset and liability accounts are translated at the exchange rates in effect as at the balance sheet date, while revenues and expenses are translated using monthly average exchange rates.

CASH AND CASH EQUIVALENTS

Cash and cash equivalents include short-term investments with a term to maturity of three months or less when purchased.

LOANS AND RECEIVABLES
Long-term notes receivable from affiliates are measured at amortized cost using the effective interest rate method, net of any impairment losses recognized. Trade receivables and unbilled revenues are measured at cost. Interest income is recognized in earnings as it is earned with the passage of time.

CURRENT EXPECTED CREDIT LOSSES
For accounts receivable, a loss allowance matrix is utilized to measure lifetime expected credit losses. The matrix contemplates historical credit losses by age of receivables, adjusted for any forward-looking information and management expectations. Other loan receivables and applicable off-balance sheet commitments utilize a discounted cash flow methodology which calculates the current expected credit losses based on historical default probability rates associated with the credit rating of the counterparty and the related term of the loan or commitment, adjusted for forward-looking information and management expectations. Trade receivables and unbilled revenues are presented net of allowance for expected credit losses of $115 million and $119 million as at December 31, 2025 and 2024, respectively.

NATURAL GAS IMBALANCES
The Consolidated Statements of Financial Position include balances resulting from differences in gas volumes received from, and delivered for, customers. As settlement of certain imbalances is in-kind, changes in the balances do not have an effect on our Consolidated Statements of Earnings or Consolidated Statements of Cash Flows. Most natural gas volumes owed to or by us are valued at natural gas market index prices as at the balance sheet dates.

INVENTORY
Inventory is comprised of natural gas held in storage by businesses in our Gas Distribution and Storage and Gas Transmission segments, crude oil and natural gas held by our crude oil and natural gas marketing businesses, and materials and supplies. Natural gas held in storage by our Gas Distribution and Storage businesses is recorded at the prices approved by the regulators in the determination of distribution rates. The actual price of gas purchased may differ from the regulator approved price. The difference between the approved price and the actual cost of gas purchased is deferred as a liability for future refund, or as an asset for collection, as approved by the regulators.

Commodity inventory held by our crude oil and natural gas marketing businesses is recorded at the lower of cost, as determined on a weighted average basis, or market value. Upon disposition, commodity inventory is recorded to Commodity costs in the Consolidated Statements of Earnings at the weighted average cost of inventory, including any adjustments recorded to reduce inventory to market value. Materials and supplies inventory is recorded at the lower of average cost or net realizable value.

PROPERTY, PLANT AND EQUIPMENT
Property, plant and equipment is recorded at historical cost. Expenditures for construction, expansion, major renewals and betterments are capitalized. Maintenance and repair costs are expensed as incurred. Expenditures for project development are capitalized if they are expected to have future benefit. We capitalize interest incurred during construction for non-rate-regulated assets. For rate-regulated assets, AFUDC is included in the cost of property, plant and equipment and is depreciated over future periods as part of the total cost of the related asset.

Two primary methods of depreciation are utilized. For distinct assets, depreciation is generally provided on a straight-line basis over the estimated useful life of the asset commencing when it is placed in service. For largely homogeneous groups of assets with comparable useful lives, the pool method of accounting is followed whereby similar assets are grouped and depreciated as a pool. When group assets are retired or otherwise disposed of, gains and losses are generally not reflected in earnings but are booked as an adjustment to accumulated depreciation.

The successful efforts method of accounting is used for cost-of-service reserves developed and produced by Wexpro for gas utility affiliates, Enbridge Gas Utah, Enbridge Gas Wyoming, and Enbridge Gas Idaho. Cost-of-service reserves are properties for which the operations and return on investment are subject to the Wexpro Agreements. Under the successful efforts method, Wexpro capitalizes the costs of acquiring leaseholds, drilling development wells, drilling successful exploratory wells, and purchasing related support equipment and facilities. Geological and geophysical studies are expensed as incurred. Capitalized costs of development wells and leaseholds are amortized on a field-by-field basis using the unit-of-production method and the estimated proved developed or total proved natural gas and crude oil reserves.

LEASES
We recognize an arrangement as a lease when a lessee has the right to obtain substantially all of the economic benefits from the use of an asset, as well as the right to direct the use of the asset. At inception, we review the facts and circumstances of the arrangement to classify lease assets as operating or finance leases under Topic 842, *Leases.* The initial measurement of both types of leases results in recognition of right-of-use (ROU) assets and the related lease liabilities in the Consolidated Statements of Financial Position for lease arrangements with a term of 12 months or longer.

For finance leases, a lessee amortizes the ROU asset and accretes the lease liability using the effective interest method. Operating leases result in the recognition of a single lease expense amount that is recorded on a straight-line basis. All ROU assets are assessed for impairment using the same approach applied for other long-lived assets.

We do not separate non-lease components from the associated lease components of our lessee contracts and account for both components as a single lease component. We combine lease and non-lease components within a contract for operating lessor leases when certain conditions are met.

Lease liabilities and ROU assets require the use of judgment and estimates which are applied in determining the term of a lease, appropriate discount rates, whether an arrangement contains a lease, whether there are any indicators of impairment for ROU assets and whether any ROU assets should be grouped with other long-lived assets for impairment testing. The lease term may include periods associated with options to extend or terminate the lease if it is reasonably certain the options will be exercised.

DEFERRED AMOUNTS AND OTHER ASSETS
Deferred amounts and other assets primarily consists of costs that regulatory authorities have permitted, or are expected to permit, to be recovered through future rates *(Note 7)*, overfunded defined benefit pension and OPEB plan assets *(Note 25)*, operating lease ROU assets *(Note 26)* and long-term gross derivative asset balances *(Note 23)*.

INTANGIBLE ASSETS
Intangible assets consist primarily of certain software costs, customer relationships and biogas rights agreements. We capitalize costs incurred during the application development stage of internal use software projects. Customer relationships represent the underlying relationship from long-term agreements with customers that are capitalized upon acquisition. Biogas rights agreements are long-term gas supply agreements with landfill owners of our landfill gas-to-RNG production facilities that are capitalized upon acquisition. Intangible assets are generally amortized on a straight-line basis over their expected lives, commencing when the asset is available for use.

GOODWILL
Goodwill represents the excess of the purchase price over the fair value of net identifiable assets upon acquisition of a business. The carrying value of goodwill, which is not amortized, is assessed for impairment annually or more frequently if events or changes in circumstances arise that suggest the carrying value of goodwill may be impaired. We perform our annual review of the goodwill balance on April 1.

We perform our annual review for impairment at the reporting unit level, which is identified by assessing whether the components of our operating segments constitute businesses for which discrete information is available, whether segment management regularly reviews the operating results of those components, and whether the economic and regulatory characteristics are similar. Our reporting units are Liquids Pipelines, Gas Transmission, Gas Distribution and Storage, and Renewable Power Generation.
We have the option to first assess qualitative factors to determine whether it is necessary to perform the quantitative goodwill impairment assessment. When performing a qualitative assessment, we determine the drivers of fair value for each reporting unit and evaluate whether those drivers have been positively or negatively affected by relevant events and circumstances since the last fair value assessment. Our evaluation includes, but is not limited to, the assessment of macroeconomic trends (including the impact of changes in discount rates and rate base multiple), changes to regulatory environments, capital accessibility, operating income trends (including changes to projected cash flows from operations, expected future capital expenditures and forecasted rate base), and changes to industry conditions. Based on our assessment of qualitative factors, if we determine it is more likely than not that the fair value of the reporting unit is less than its carrying amount, a quantitative goodwill impairment assessment is performed.

The quantitative goodwill impairment assessment involves determining the fair value of our reporting units and comparing those values to the carrying value of each reporting unit. If the carrying value of a reporting unit, including allocated goodwill, exceeds its fair value, goodwill impairment is measured at the amount by which the reporting unit's carrying value exceeds its fair value. This amount should not exceed the carrying amount of goodwill. The fair value of our reporting units is estimated using either a discounted cash flow technique or a combination of discounted cashflow and earnings multiples techniques. The determination of fair value using the discounted cash flow technique requires the use of estimates and assumptions related to discount rates, projected operating income, expected future capital expenditures, as well as terminal value growth rates for the Liquids Pipelines, Gas Transmission, and Renewable Power Generation reporting units, and projected regulatory rate base and rate base multiple for the Gas Distribution and Storage reporting unit. The determination of fair value using the earnings multiples technique requires assumptions to be made in relation to maintainable earnings and earnings multiples.

The allocation of goodwill to held-for-sale and disposed businesses is based on the relative fair value of businesses included in the relevant reporting unit.

On April 1, 2025, we performed our annual goodwill impairment assessment which consisted of a qualitative assessment for the Liquids Pipelines and Renewable Power Generation reporting units and did not identify any impairment indicators. We also chose to perform a quantitative assessment for the Gas Transmission and Gas Distribution and Storage reporting units which did not result in the recognition of any impairment charges. No indicators of goodwill impairment were identified during the remainder of 2025.

IMPAIRMENT
We review the carrying values of our long-lived assets as events or changes in circumstances warrant. If it is determined that the carrying value of an asset exceeds its expected undiscounted cash flows, we will calculate fair value based on the discounted cash flows and write the asset down to the extent that the carrying value exceeds the fair value.

With respect to investments in debt securities and equity investments, we assess at each balance sheet date whether there is objective evidence that a financial asset is impaired by completing a qualitative or quantitative analysis of factors impacting the investment. If there is objective evidence of impairment, we value the expected discounted cash flows using observable market inputs. We determine whether the decline below carrying value is other-than-temporary for equity investments or is due to a credit loss for investments in debt securities. If the decline is determined to be other-than-temporary for equity investments or is due to a credit loss for investments in debt securities, an impairment charge is recorded in earnings with an offsetting reduction to the carrying value of the investment.

ASSET RETIREMENT OBLIGATIONS
ARO associated with the retirement of long-lived assets are measured at fair value and recognized as Other current liabilities or Other long-term liabilities in the period in which they can be reasonably determined. Fair value approximates the cost a third party would charge to perform the tasks necessary to retire such assets and is recognized at the present value of expected future cash flows. ARO is added to the carrying value of the associated asset and depreciated over the asset's useful life. The corresponding liability is accreted over time through charges to earnings and is reduced by actual costs of decommissioning and reclamation. Our estimates of retirement costs could change as a result of changes in cost estimates and regulatory requirements. Currently, for the majority of our assets, it is not possible to make a reasonable estimate of ARO due to the indeterminate timing and scope of the asset retirements.

PENSION AND OTHER POSTRETIREMENT BENEFITS
We sponsor defined benefit and defined contribution pension plans, as well as defined benefit OPEB plans.

Obligations and net periodic benefit costs for defined benefit pension and OPEB plans are estimated using the projected unit credit method, which is based on years of service, as well as our best estimates of actuarial assumptions such as discount rates, future salary levels, other cost escalations, employees' retirement ages, and mortality.

We determine discount rates using market yields of high-quality corporate bonds with maturities that approximate the estimated timing of future benefit payments.

Plan assets are measured at fair value. The expected return on plan assets is determined using the long-term target asset mixes in our investment policies and long-term market expectations.

Actuarial gains and losses arise from the difference between the actual and expected return on plan assets, and changes in actuarial assumptions such as discount rates. Periodic net actuarial gains and losses and prior service costs are accumulated and presented as follows in the Consolidated Statements of Financial Position:

- as a component of AOCI; or
- as a component of Deferred amounts and other assets and/or Other long-term liabilities for certain utilities' defined benefit pension plans and OPEB plans, to the extent that the net actuarial gains and losses and prior service costs have been permitted or are expected to be permitted by the regulators, to be recovered through future rates.

Net periodic benefit cost is recognized in earnings and includes:

- current service cost;
- interest cost;
- expected return on plan assets;
- amortization of prior service costs over the expected average remaining service life of the plans' active employee group; and
- amortization of net actuarial gains and losses in excess of 10% of the greater of the benefit obligation or the fair value of plan assets over the expected average remaining service life of the plans' active employee group.

Our utility operations also record regulatory adjustments for the difference between net periodic benefit costs for accounting versus ratemaking purposes. Offsetting regulatory assets or liabilities are recorded to the extent net periodic benefit costs are expected to be recovered from or refunded to customers, respectively, in future rates. In the absence of rate regulation, regulatory assets or liabilities would not be recorded and net periodic benefit costs would be charged to earnings and OCI on an accrual basis.

For defined contribution plans, our contributions are expensed when they occur.

STOCK-BASED COMPENSATION

Incentive stock options (ISO) granted are recorded using the fair value method. Under this method, compensation expense is measured at the grant date based on the fair value of the ISO granted as calculated by the Black-Scholes-Merton model and is recognized on a straight-line basis over the shorter of the vesting period or the period to early retirement eligibility, with a corresponding credit to Additional paid-in capital. Balances in Additional paid-in capital are transferred to Share capital when the options are exercised.

Performance stock units (PSU) and certain RSUs are cash-settled awards for which the related liability is remeasured each reporting period. PSUs vest at the completion of a three-year term and RSUs vest one-third annually from the grant date. During the vesting term, compensation expense is recorded based on the number of units outstanding and the current market price of Enbridge's common shares with an offset to Other current liabilities or Other long-term liabilities. The value of the PSUs is also dependent on our performance relative to targets set out under the plan. We also award share-settled RSUs to certain non-executive senior management employees which vest at the completion of a three-year term. Share-settled RSUs are also granted to non-executive employees, which vest either one-third annually from the grant date, or following a 12-month period. During the vesting term, compensation expense is recorded based on the number of units granted and the market price of Enbridge's common shares on the day immediately preceding the grant date, with an offset to Additional paid-in capital. There is no associated liability recorded for share-settled awards.

COMMITMENTS, CONTINGENCIES AND ENVIRONMENTAL LIABILITIES

We expense or capitalize, as appropriate, expenditures for ongoing compliance with environmental regulations that relate to past or current operations. We expense costs incurred for remediation of existing environmental contamination caused by past operations that do not benefit future periods by preventing or eliminating future contamination. We record liabilities for environmental matters when assessments indicate that remediation efforts are probable and the costs can be reasonably estimated. Estimates of environmental liabilities are based on currently available facts, existing technology and presently enacted laws and regulations, taking into consideration the likely effects of inflation and other factors. These amounts also consider prior experience in remediating contaminated sites, other companies' clean-up experience and data released by government organizations. Our estimates are subject to revision in future periods based on actual costs or new information and are included in Other current liabilities and Other long-term liabilities in the Consolidated Statements of Financial Position at their undiscounted amounts. There is always a potential of incurring additional costs in connection with environmental liabilities due to variations in any or all of the categories described above, including modified or revised requirements from regulatory agencies, in addition to fines and penalties, as well as expenditures associated with litigation and settlement of claims. We evaluate recoveries from insurance coverage separately from the liability and, when recovery is probable, we record and report an asset separately from the associated liability in the Consolidated Statements of Financial Position.

Liabilities for other commitments and contingencies are recognized when, after fully analyzing available information, we determine it is either probable that an asset has been impaired or that a liability has been incurred, and the amount of impairment or loss can be reasonably estimated. When a range of probable loss can be estimated, we recognize the most likely amount, or if no amount is more likely than another, the minimum of the range of probable loss is accrued. We expense legal costs associated with loss contingencies as such costs are incurred.

3. CHANGES IN ACCOUNTING POLICIES

The following policy became significant to Enbridge on July 2, 2025:

Noncontrolling Interests
NCI represent ownership interests attributable to third parties in certain consolidated subsidiaries. The portion of equity not owned by us in such entities is reflected as NCI within the equity section of the Consolidated Statements of Financial Position and, in the case of Redeemable NCI, within the mezzanine equity section of the Consolidated Statements of Financial Position between long-term liabilities and equity.

Westcoast Energy Limited Partnership's (Westcoast LP) Class A noncontrolling unitholder has the option, exercisable at any time from and after July 2, 2035, to require the Class B and Class C unitholders of Westcoast LP to redeem all of the Class A units for cash at the then-current fair value, subject to certain limitations. On a quarterly basis, the Redeemable NCI carrying amount of the Class A units is recognized at the higher of the amount resulting from the application of Accounting Standards Codification (ASC) 810 *Consolidation* and the estimated current redemption value, with measurement adjustments to the carrying amount of Redeemable NCI recognized in retained earnings (redemption value adjustment). The measurement adjustments to Redeemable NCI that are recognized in retained earnings impact our earnings per common share *(Note 6)*. The estimated current redemption value is determined using the income approach, with key assumptions being forecasted cash flows and market participant discount rate.

ADOPTION OF NEW ACCOUNTING STANDARDS
Income Tax Disclosures
Effective January 1, 2025, we adopted Accounting Standards Update (ASU) 2023-09 on a retrospective basis beginning on January 1, 2023. The standard was issued in December 2023 to improve tax disclosures by requiring specified categories in the annual rate reconciliation that meet quantitative thresholds and further disaggregation on income taxes paid by jurisdiction. Upon adoption of the ASU, we have amended the presentation of *Note 24 - Income Taxes* to align with the new standard.

FUTURE ACCOUNTING POLICY CHANGES
Disaggregation of Income Statement Expenses
ASU 2024-03 was issued in November 2024 to improve financial reporting by requiring entities to disclose additional information about specific expense categories in the notes to financial statements at interim and annual reporting periods. The ASU requires entities to disclose 1) the amounts of (a) purchases of inventory, (b) employee compensation, (c) depreciation, (d) intangible asset amortization, (e) depreciation, depletion and amortization recognized as part of oil and gas producing activities, (f) expense reimbursements included in a relevant expense caption, and (g) selling expenses, and 2) a qualitative description of the amounts remaining in relevant expense captions that are not separately disaggregated quantitatively. ASU 2024-03 is effective January 1, 2027, with interim period disclosure requirements effective after January 1, 2028 and can be applied either prospectively or retrospectively. The additional note disclosures will be included in our December 31, 2027 annual consolidated financial statements and in our interim financial statements beginning in 2028.

4. REVENUE

REVENUE FROM CONTRACTS WITH CUSTOMERS

Major Products and Services

Year ended December 31, 2025	Liquids Pipelines	Gas Transmission	Gas Distribution and Storage	Renewable Power Generation	Eliminations and Other	Consolidated
(millions of Canadian dollars)						
Transportation revenue	**11,924**	**5,608**	**250**	**—**	**—**	**17,782**
Storage and other revenue	**289**	**663**	**586**	**—**	**—**	**1,538**
Gas distribution sales	**—**	**—**	**9,610**	**—**	**—**	**9,610**
Electricity revenue	**—**	**—**	**—**	**232**	**—**	**232**
Commodity sales	**—**	**137**	**30**	**—**	**—**	**167**
Total revenue from contracts with customers	**12,213**	**6,408**	**10,476**	**232**	**—**	**29,329**
Commodity sales	**33,418**	**164**	**—**	**—**	**1,432**	**35,014**
Other revenue[1,2]	**313**	**59**	**157**	**322**	**—**	**851**
Intersegment revenue	**—**	**21**	**21**	**7**	**(49)**	**—**
Total revenue	**45,944**	**6,652**	**10,654**	**561**	**1,383**	**65,194**

Year ended December 31, 2024	Liquids Pipelines	Gas Transmission	Gas Distribution and Storage	Renewable Power Generation	Eliminations and Other	Consolidated
(millions of Canadian dollars)						
Transportation revenue	11,958	5,279	237	—	—	17,474
Storage and other revenue	255	573	493	—	—	1,321
Gas distribution sales	—	—	6,746	—	—	6,746
Electricity revenue	—	—	—	189	—	189
Commodity sales	—	158	—	—	—	158
Total revenue from contracts with customers	12,213	6,010	7,476	189	—	25,888
Commodity sales	25,689	99	—	—	1,072	26,860
Other revenue[1,2]	281	70	55	319	—	725
Intersegment revenue	—	20	11	6	(37)	—
Total revenue	38,183	6,199	7,542	514	1,035	53,473

Year ended December 31, 2023	Liquids Pipelines	Gas Transmission	Gas Distribution and Storage	Renewable Power Generation	Eliminations and Other	Consolidated
(millions of Canadian dollars)						
Transportation revenue	11,875	5,302	148	—	—	17,325
Storage and other revenue	257	461	352	—	—	1,070
Gas distribution sales	—	—	5,426	—	—	5,426
Electricity revenue	—	—	—	259	—	259
Commodity sales	—	17	—	—	—	17
Total revenue from contracts with customers	12,132	5,780	5,926	259	—	24,097
Commodity sales	17,494	—	—	—	1,470	18,964
Other revenue[1,2]	257	72	44	215	—	588
Intersegment revenue	(1)	2	6	3	(10)	—
Total revenue	29,882	5,854	5,976	477	1,460	43,649

1 Includes realized and unrealized gains and losses from our hedging program which were net gains of $160 million and $23 million and a net loss of $97 million for the years ended December 31, 2025, 2024 and 2023, respectively.
2 Includes revenues from lease contracts. Refer to Note 26 - Leases.

We disaggregate revenue into categories which represent our principal performance obligations within each business segment. These revenue categories represent the most significant revenue streams in each segment and consequently are considered to be the most relevant revenue information for management to consider in evaluating performance.

Contract Balances

	Contract Receivables	Contract Assets	Contract Liabilities
(millions of Canadian dollars)			
Balance as at December 31, 2025	**3,799**	**315**	**2,765**
Balance as at December 31, 2024	3,764	330	2,828

Contract receivables represent the amount of receivables derived from contracts with customers.

Contract assets represent the amount of revenue which has been recognized in advance of payments received for performance obligations we have fulfilled (or have partially fulfilled) and prior to the point in time at which our right to payment is unconditional. Amounts included in contract assets are transferred to accounts receivable when our right to receive the consideration becomes unconditional.

Contract liabilities represent payments received for performance obligations which have not been fulfilled. Contract liabilities primarily relate to make-up rights and deferred revenues. Revenue recognized during the year ended December 31, 2025 included in contract liabilities at the beginning of the period was $455 million. Increases in contract liabilities from cash received, net of amounts recognized as revenues, during the year ended December 31, 2025 was $481 million.

Performance Obligations

Segment	Nature of Performance Obligation
Liquids Pipelines	• Transportation and storage of crude oil and natural gas liquids (NGL)
Gas Transmission	• Transportation, storage, gathering, compression and treating of natural gas • Transportation of crude oil and NGL • Sale of renewable natural gas and its attached environmental attributes
Gas Distribution and Storage	• Supply and delivery of natural gas • Transportation of natural gas • Storage of natural gas
Renewable Power Generation	• Generation and transmission of electricity • Delivery of electricity from renewable energy generation facilities

There was no material revenue recognized in the year ended December 31, 2025 from performance obligations satisfied in previous periods.

Payment Terms

Payments are received monthly from customers under long-term transportation, commodity sales, and gas gathering and processing contracts. Payments from Gas Distribution and Storage customers are received on a continuous basis based on established billing cycles.

Certain contracts in our US offshore business provide for us to receive a series of fixed monthly payments (FMPs) for a specified period that is less than the period during which the performance obligations are satisfied. As a result, a portion of the FMPs are recorded as contract liabilities. The FMPs are not considered to be a financing arrangement as payments are scheduled to match the production profiles of offshore oil and gas fields, which generate greater revenue in the initial years of their productive lives.

Revenue to be Recognized from Unfulfilled Performance Obligations

The following table presents our estimated revenue allocated to remaining performance obligations for contracted revenue that has not yet been recognized, that is expected to be recognized in the following periods:

	Total	1 year	2-5 years	Thereafter
(billions of Canadian dollars)				
Expected revenue	59.1	9.7	24.6	24.8

The revenues excluded from the amounts above based on optional exemptions available under ASC 606, as explained below, represent a significant portion of our overall revenues and revenues from contracts with customers. Certain revenues such as flow-through operating costs charged to shippers are recognized at the amount for which we have the right to invoice our customers and are excluded from the amounts for revenues to be recognized in the future from unfulfilled performance obligations above. Variable consideration is excluded from the amounts above due to the uncertainty of the associated consideration, which is generally resolved when actual volumes and prices are determined. For example, we consider interruptible transportation service revenues to be variable revenues since volumes cannot be estimated. Additionally, the effect of escalation on certain tolls which are contractually escalated for inflation has not been reflected in the amounts above as it is not possible to reliably estimate future inflation rates. Revenues for periods extending beyond the current rate settlement term for regulated contracts where the tolls are periodically reset by the regulator are excluded from the amounts above since future tolls remain unknown. Finally, revenues from contracts with customers which have an original expected duration of one year or less are excluded from the amounts above.

SIGNIFICANT JUDGMENTS MADE IN RECOGNIZING REVENUE

Long-Term Transportation Agreements

For long-term transportation agreements, significant judgments pertain to the period over which revenue is recognized and whether the agreement provides for make-up rights for the shippers. Transportation revenue earned from firm contracted capacity arrangements is recognized ratably over the contract period. Transportation revenue from interruptible or volumetric-based arrangements is recognized when services are performed.

Variable Consideration

Revenue from arrangements subject to variable consideration is recognized only to the extent that it is probable that a significant reversal in the amount of cumulative revenue recognized will not occur when the uncertainty associated with the variable consideration is subsequently resolved. Uncertainties associated with variable consideration relate principally to differences between estimated and actual volumes and prices. These uncertainties are resolved each month when actual volumes are sold or transported and actual tolls and prices are determined.

On March 4, 2024, the CER approved the negotiated Mainline Tolling Settlement (MTS). The new tolls were finalized and were in effect on an interim basis on July 1, 2023, and the overall agreement is retroactively effective as of July 1, 2021 through to the end of 2028.

Recognition and Measurement of Revenues

Year ended December 31, 2025	Liquids Pipelines	Gas Transmission	Gas Distribution and Storage	Renewable Power Generation	Consolidated
(millions of Canadian dollars)					
Revenues from products transferred at a point in time	**—**	**137**	**161**	**55**	**353**
Revenues from products and services transferred over time[1]	**12,213**	**6,271**	**10,315**	**177**	**28,976**
Total revenue from contracts with customers	**12,213**	**6,408**	**10,476**	**232**	**29,329**

Year ended December 31, 2024	Liquids Pipelines	Gas Transmission	Gas Distribution and Storage	Renewable Power Generation	Consolidated
(millions of Canadian dollars)					
Revenues from products transferred at a point in time	—	158	137	—	295
Revenues from products and services transferred over time[1]	12,213	5,852	7,339	189	25,593
Total revenue from contracts with customers	12,213	6,010	7,476	189	25,888

Year ended December 31, 2023	Liquids Pipelines	Gas Transmission	Gas Distribution and Storage	Renewable Power Generation	Consolidated
(millions of Canadian dollars)					
Revenues from products transferred at a point in time	—	17	138	—	155
Revenues from products and services transferred over time[1]	12,132	5,763	5,788	259	23,942
Total revenue from contracts with customers	12,132	5,780	5,926	259	24,097

1 Revenue from crude oil and natural gas pipeline transportation, storage, natural gas gathering, compression and treating, natural gas distribution, natural gas storage services and electricity sales.

Performance Obligations Satisfied Over Time

For arrangements involving the transportation and sale of petroleum products and natural gas where the transportation services or commodities are simultaneously received and consumed by the shipper or customer, we recognize revenue over time using an output method based on volumes of commodities delivered or transported. The measurement of the volumes transported or delivered corresponds directly to the benefits received by the shippers or customers during that period.

Determination of Transaction Prices

Prices for transportation and gas processing services are determined based on the capital cost of the facilities, pipelines and associated infrastructure required to provide such services, plus a rate of return on capital invested that is determined either through negotiations with customers or through regulatory processes for those operations that are subject to rate regulation.

Prices for commodities sold are determined by reference to market price indices, plus or minus a negotiated differential and in certain cases a marketing fee.

Prices for natural gas sold and distribution services provided by regulated natural gas distribution operations are prescribed by regulation.

5. SEGMENTED INFORMATION

Year ended December 31, 2025	Liquids Pipelines	Gas Transmission	Gas Distribution and Storage[1]	Renewable Power Generation	Total Reportable Segments
(millions of Canadian dollars)					
Operating revenues[2]	**45,944**	**6,652**	**10,654**	**561**	**63,811**
Commodity and gas distribution costs	**(33,038)**	**(68)**	**(3,709)**	**2**	**(36,813)**
Operating and administrative	**(4,440)**	**(2,252)**	**(3,030)**	**(332)**	**(10,054)**
Impairment of long-lived assets	**(240)**	**—**	**(330)**	**—**	**(570)**
Income from equity investments	**1,091**	**853**	**4**	**291**	**2,239**
Other income	**79**	**306**	**220**	**98**	**703**
Earnings before interest, income taxes and depreciation and amortization	**9,396**	**5,491**	**3,809**	**620**	**19,316**
Eliminations and Other					**1,161**
Depreciation and amortization					**(5,661)**
Interest expense *(Note 17)*					**(5,023)**
Earnings before income taxes					**9,793**

Year ended December 31, 2024	Liquids Pipelines	Gas Transmission	Gas Distribution and Storage[1]	Renewable Power Generation	Total Reportable Segments
(millions of Canadian dollars)					
Operating revenues[2]	38,183	6,199	7,542	514	52,438
Commodity and gas distribution costs	(25,283)	(130)	(2,501)	4	(27,910)
Operating and administrative	(4,495)	(2,322)	(2,276)	(304)	(9,397)
Impairment of long-lived assets	(2)	(162)	(3)	(23)	(190)
Income from equity investments	1,051	812	3	455	2,321
Gain on disposition of equity investments *(Note 13)*	—	1,063	—	28	1,091
Other income	77	196	104	59	436
Earnings before interest, income taxes and depreciation and amortization	9,531	5,656	2,869	733	18,789
Eliminations and Other					(1,904)
Depreciation and amortization					(5,167)
Interest expense *(Note 17)*					(4,419)
Earnings before income taxes					7,299

Year ended December 31, 2023	Liquids Pipelines	Gas Transmission	Gas Distribution and Storage[1]	Renewable Power Generation	Total Reportable Segments
(millions of Canadian dollars)					
Operating revenues[2]	29,882	5,854	5,976	477	42,189
Commodity and gas distribution costs	(17,106)	(15)	(2,871)	(20)	(20,012)
Operating and administrative	(4,659)	(2,380)	(1,285)	(261)	(8,585)
Impairment of long-lived assets[3]	145	—	(281)	(283)	(419)
Income from equity investments	1,007	688	2	140	1,837
Other income	114	117	51	96	378
Earnings before interest, income taxes and depreciation and amortization	9,383	4,264	1,592	149	15,388
Eliminations and Other					916
Depreciation and amortization					(4,613)
Interest expense *(Note 17)*					(3,812)
Earnings before income taxes					7,879

1 *Primarily relates to public utilities that are subject to regulation.*
2 *Refer to* Note 4 - Revenue *for a reconciliation of segment Operating revenues to the Consolidated Statements of Earnings.*
3 *The Liquids Pipelines segment includes the impact of a gain resulting from the derecognition of a net regulatory liability due to the discontinuance of regulatory accounting for our Southern Lights Pipeline.*

Capital Expenditures[1]

Year ended December 31,	**2025**	2024	2023
(millions of Canadian dollars)			
Liquids Pipelines	**1,358**	1,157	1,158
Gas Transmission	**3,271**	2,571	1,944
Gas Distribution and Storage	**3,351**	2,386	1,451
Renewable Power Generation	**947**	661	100
Eliminations and Other	**174**	59	55
	9,101	6,834	4,708

1 *Capital expenditures are cash basis plus equity component of the allowance for funds used during construction.*

Property, Plant and Equipment

Year ended December 31,	**2025**	2024
(millions of Canadian dollars)		
Liquids Pipelines	**51,689**	53,863
Gas Transmission	**35,421**	34,683
Gas Distribution and Storage	**39,644**	38,636
Renewable Power Generation	**4,439**	3,612
Eliminations and Other	**405**	310
	131,598	131,104

GEOGRAPHIC INFORMATION
Revenues[1]

Year ended December 31,	**2025**	2024	2023
(millions of Canadian dollars)			
Canada	**23,077**	22,001	23,781
US	**42,117**	31,472	19,868
	65,194	53,473	43,649

1 Revenues are based on the country of origin of the product or service sold.

Property, Plant and Equipment[1]

Year ended December 31,	**2025**	2024
(millions of Canadian dollars)		
Canada	**49,642**	48,873
United States	**81,956**	82,231
	131,598	131,104

1 Amounts are based on the locations where the assets are held.

6. EARNINGS PER COMMON SHARE

NUMERATOR
The numerator used in calculating both basic and diluted earnings per share equals Earnings attributable to common shareholders per the Consolidated Statements of Earnings, less Redemption value adjustment attributable to redeemable NCI per the Consolidated Statements of Changes in Equity.

DENOMINATOR
The denominator of the basic earnings per common share calculation represents the weighted average number of common shares outstanding.

The denominator of the diluted earnings per common share calculation uses the treasury stock method to determine the dilutive impact of stock options and share-settled RSUs. This method assumes any proceeds from the exercise of stock options and vesting of share-settled RSUs would be used to purchase common shares at the average market price during the period. The basic weighted average shares outstanding are adjusted by this dilutive impact to derive the diluted weighted average shares outstanding.

Weighted average shares outstanding used to calculate basic and diluted earnings per common share are as follows:

December 31,	**2025**	2024	2023
(number of shares in millions)			
Weighted average shares outstanding	**2,180**	2,155	2,056
Effect of dilutive options and RSUs	**6**	3	2
Diluted weighted average shares outstanding	**2,186**	2,158	2,058

For the years ended December 31, 2025, 2024 and 2023, 1.2 million, 14.6 million and 19.3 million, respectively, of anti-dilutive stock options with a weighted average exercise price of $60.37, $54.37 and $54.42, respectively, were excluded from the diluted earnings per common share calculation.

7. REGULATORY MATTERS

We record assets and liabilities that result from regulated ratemaking processes that would not be recorded under US GAAP for non-regulated entities. See *Note 2 - Significant Accounting Policies* for further discussion. Our significant regulated businesses and the related accounting impacts are described below.

Under the current authorized rate structure for certain operations, income tax costs are recovered in rates based on the current income tax payable and do not include accruals for deferred income tax. However, as income taxes become payable as a result of the reversal of temporary differences that created the deferred income taxes, it is expected that rates will be adjusted to recover these taxes. Since most of these temporary differences are related to property, plant and equipment costs, this recovery is expected to occur over the life of the related assets. In the absence of rate-regulated accounting, this regulatory tax asset and the related earnings impact would not be recorded.

LIQUIDS PIPELINES
Canadian Mainline
Canadian Mainline includes the Canadian portion of our Mainline system. The MTS governs the tolls paid for products shipped on its Mainline System, with the exception of Lines 8 and 9 which are tolled on a separate basis, and was approved by the CER on March 4, 2024. The MTS has a seven-and-a-half year term through the end of 2028 and provides a Canadian Local Toll for all volumes shipped on the Canadian Mainline and an International Joint Tariff for all volumes shipped from western Canadian receipt points to delivery points on our Lakehead System. We have recognized a regulatory asset of $2.0 billion as at December 31, 2025 and 2024 to offset deferred income taxes, as a CER rate order governing flow-through income tax treatment permits future recovery. We also collect and set aside amounts to fund future pipeline abandonment costs for our regulated pipelines as a result of the requirements under the LMCI *(Note 23)*. Amounts expected to be paid for these future costs are recognized as long-term regulatory liabilities. No other material regulatory assets or liabilities are recognized under the terms of the MTS.

GAS TRANSMISSION
British Columbia Pipeline and Maritimes & Northeast Canada
British Columbia (BC) Pipeline and Maritimes & Northeast Canada (M&N Canada) are regulated by the CER. Rates are approved by the CER through negotiated toll settlement agreements based on cost-of-service. Both our BC Pipeline and M&N Canada systems currently operate under the terms of their respective 2022–2026 and 2024–2025 settlement agreements, which stipulate an allowable return on equity (ROE) and the continuation and establishment of certain deferral and variance accounts. The M&N Canada 2024–2025 toll settlement expired at the end of 2025. M&N Canada reached a new toll settlement with shippers for the effective period from January 1, 2026 to December 31, 2027. On December 15, 2025, M&N Canada filed the 2026–2027 toll settlement agreement with the CER, which is currently pending CER approval.

US Gas Transmission
The majority of our US gas transmission and storage services are regulated by the FERC and may also be subject to the jurisdiction of various other federal, state and local agencies. The FERC regulates natural gas transmission in US interstate commerce including the establishment of rates for services, while rates for intrastate commerce and/or gathering services are regulated by the state gas commissions. Cost-of-service is the basis for the calculation of regulated tariff rates, although the FERC also allows the use of negotiated and discounted rates within contracts with shippers that may result in a rate that is above or below the FERC-regulated recourse rate for that service.

GAS DISTRIBUTION AND STORAGE
Enbridge Gas Ontario
Enbridge Gas Ontario's distribution rates, commencing in 2024, were set by the OEB under a five-year Incentive Regulation (IR) framework. The framework included the establishment of 2024 base rates on a cost-of-service basis, while rates for 2025 through 2028 were or will be established using a price cap mechanism. The price cap mechanism establishes new rates each year through certain annual base rate adjustments and updates, and annual base rate escalation at inflation less a 0.28% productivity factor. The price cap mechanism includes the continuation and establishment of certain deferral and variance accounts, as well as an earnings sharing mechanism that requires Enbridge Gas Ontario to share equally with customers any earnings in excess of 100 basis points over the allowed ROE, and share 90% of earnings in excess of 300 basis points over the allowed ROE.

Enbridge Gas Ohio
Enbridge Gas Ohio is subject to the jurisdiction of the Ohio Commission with its natural gas sales and transportation and storage services being provided under rate schedules approved by the regulatory commission. Enbridge Gas Ohio uses a straight-fixed-variable rate design, where the majority of operating costs are recovered through a monthly charge, as established in a 2008 rate case settlement.

In October 2023, Enbridge Gas Ohio filed its first base rates application with the Ohio Commission since 2007, proposing a base rate annual revenue increase to be effective January 2025. The base rate increase was proposed to recover the significant investment in distribution infrastructure for the benefit of Ohio customers, including an ROE of 10.40%.

In June 2025, the Ohio Commission ordered a decrease to annual revenue of US$26.3 million, utilizing an ROE of 9.79%, and an increase to the equity thickness to 51.9%. The order also resulted in disallowances of $330 million (US$240 million), including regulatory pension assets of $280 million (US$204 million) and other disallowances of $50 million (US$36 million). The impairment loss of $330 million for the year ended December 31, 2025, is included in Impairment of long-lived assets in the Consolidated Statements of Earnings.

The order authorized the continuation of the Pipeline Infrastructure Replacement (PIR) and Capital Expenditure Programs (CEP) through 2028, with 3% increases of capital expenditures under the PIR per year. Assets placed in service accrue a carrying cost at the cost of long-term debt approved in the most recent rate case until incorporated into rates via annual filings.

In July 2025, Enbridge Gas Ohio filed a rehearing application for certain aspects of the order. The Ohio Commission corrected errors in its order addressing the rehearing application, resulting in a reduction of the original annual revenue decrease to US$14.3 million. Updated rates were effective on November 1, 2025. On December 12, 2025, Enbridge Gas Ohio filed a notice of appeal with the Ohio Supreme Court, focusing on the Ohio Commission's treatment of the pension fund and capitalized incentive-compensation costs.

In December 2025, Enbridge Gas Ohio filed a base rate case application proposing an annual revenue increase of US$163 million, subject to update and adjustments, to be effective in early 2027. The base rate increase was proposed to recover Enbridge Gas Ohio's investment in distribution infrastructure and other costs to serve, including operating expenses and debt servicing costs.

The CEP allows Enbridge Gas Ohio to defer depreciation expense, property tax expense and carrying costs at the debt rate of 6.5% on capital investments not covered by its PIR program. In September 2024, the Ohio Commission approved adjustments to CEP cost recovery rates for 2023 costs. In March 2025, Enbridge Gas Ohio filed an application with the Ohio Commission to adjust CEP cost recovery rates for 2024 costs. Although this application is still pending, revised base rates went into effect in November 2025 on an interim basis, with any true-up to be included in the subsequent annual filing. Enbridge Gas Ohio also updated the debt rate for carrying costs to 3.16%.

The PIR program aims to replace 25% of the pipeline system. In June 2025, the Ohio Commission extended the PIR program through 2028.

Enbridge Gas Utah, Enbridge Gas Wyoming and Enbridge Gas Idaho

Enbridge Gas Utah, Enbridge Gas Wyoming and Enbridge Gas Idaho are regulated by the Utah Commission, the Wyoming Commission, and the Idaho Commission. For rate oversight of Enbridge Gas Idaho's operations in a small area of southeastern Idaho, the Idaho Commission has contracted with Utah Commission. Both Utah and Wyoming Commissions allow for the recovery of gas costs through a balancing-account mechanism.

Enbridge Gas Utah, Enbridge Gas Wyoming and Enbridge Gas Idaho use several mechanisms to manage costs and promote efficiency including:

- recovery of gas costs through a balance-account mechanism that adjusts rates periodically to reflect changes in natural gas prices;
- a mechanism to place into rate base, and earn a return on, capital expenditures associated with the Infrastructure Replacement Program;
- decoupling of non-gas revenues from customer usage under the CET, enabling the collection of allowed revenue per customer and encouraging energy conservation; and
- promoting natural gas conservation through advertising, rebates, and home energy plans under the Energy Efficiency Program.

In May 2025, Enbridge Gas Utah filed its first rates application since 2022 with the Utah Commission, proposing the recovery of costs to deliver natural gas to customers and investments in infrastructure to support service reliability and customer growth.

In September 2025, Enbridge Gas Utah filed a settlement and final order approving an annual revenue increase of US$61 million was issued on December 24, 2025 with updated rates effective January 1, 2026.

Enbridge Gas North Carolina

Enbridge Gas North Carolina is subject to regulation of rates and other aspects of its business by the North Carolina Commission. Base rates for Enbridge Gas North Carolina are designed primarily based on rate design methodology in which the majority of operating costs are recovered through volumetric charges. The North Carolina Commission authorized Enbridge Gas North Carolina to use a tracker mechanism to recover costs related to pipeline integrity and safety requirements that are not included in current base rates.

Enbridge Gas North Carolina uses several mechanisms to adjust rates and recover costs. CUT allows for rate adjustments based on changes in customer usage patterns. Rider D enables the recovery of gas purchases from customers, with rates periodically adjusted to reflect market price changes.

In April 2025, Enbridge Gas North Carolina filed its first rates application since 2021 with the North Carolina Commission, proposing the recovery of costs to deliver natural gas to customers and investments in infrastructure to support service reliability and customer growth.

In September 2025, a settlement agreement was filed reflecting an annual revenue increase of US$33 million. The settlement was approved by the North Carolina Commission on December 9, 2025, with updated rates effective November 1, 2025.

The settlement includes a Major Projects Rider for the Moriah Energy Center LNG facility and the T-15 Reliability Project, as a standalone cost recovery mechanism between general base rate cases.

FINANCIAL STATEMENT EFFECTS

Accounting for rate-regulated activities has resulted in the recognition of the following regulatory assets and liabilities in the Consolidated Statements of Financial Position.

December 31,	**2025**	2024	Recovery/Refund Period Ends
(millions of Canadian dollars)			
Current regulatory assets			
Purchase gas variance	**124**	74	2026
Under-recovery of fuel costs	**144**	4	2026
Deferred projects costs[1]	**96**	90	2026
Other current regulatory assets	**330**	304	2026
Total current regulatory assets[2] *(Note 9)*	**694**	472	
Long-term regulatory assets			
Deferred income taxes[3]	**4,847**	4,698	Various
Deferred projects costs[1]	**1,009**	1,045	Various
Long-term debt[4]	**291**	318	2032–2046
Negative salvage[5]	**208**	136	Various
Demand-side management costs	**185**	237	Various
Pension plan receivable[6]	**18**	266	Various
Other long-term regulatory assets	**347**	447	Various
Total long-term regulatory assets[2]	**6,905**	7,147	
Total regulatory assets	**7,599**	7,619	
Current regulatory liabilities			
Purchase gas variance	**200**	292	2026
Other current regulatory liabilities	**333**	324	2026
Total current regulatory liabilities[8] *(Note 16)*	**533**	616	
Long-term regulatory liabilities			
Future removal and site restoration reserves[9]	**3,029**	2,964	Various
Regulatory liability related to US income taxes[7]	**1,852**	2,021	Various
Pipeline future abandonment costs *(Note 23)*	**949**	826	Various
Pension plan payable[6]	**100**	59	Various
Other long-term regulatory liabilities	**283**	242	Various
Total long-term regulatory liabilities[8]	**6,213**	6,112	
Total regulatory liabilities	**6,746**	6,728	

1 Amounts anticipated to be collected from customers in East Ohio's service areas for rider projects, including CEP, PIR and costs related to the Pipeline Safety Management Program. The recovery periods for these expenditures vary according to the stipulations outlined in the respective riders. For Enbridge Gas North Carolina, these amounts relate to pipeline integrity management which represent operating costs incurred to comply with federal regulatory requirements related to natural gas pipelines and have been deferred pending future approval of rate recovery.

2 Current regulatory assets are included in Other current assets, while long-term regulatory assets are included in Deferred amounts and other assets.

3 Regulatory offset to deferred income tax liabilities to the extent that it is expected to be included in future regulator-approved rates and recovered from customers. The recovery period depends on the timing of the reversal of temporary differences. In the absence of rate-regulated accounting, this regulatory balance and the related earnings impact would not be recorded. This balance is net of regulatory deferred tax write-offs.

4 Regulatory offset to the fair value adjustment to debt acquired in our merger with Spectra Energy Corp. (Spectra Energy). The offset is viewed as a proxy for the regulatory asset that would be recorded in the event such debt was extinguished at an amount higher than the carrying value.

5 Recovery in future rates of the actual cost of removal of previously retired or decommissioned plant assets, as approved by the FERC.

6 Regulatory offset to our pension liability to the extent that it is expected to be included in regulator-approved future rates and recovered from customers. The settlement period for this balance is not determinable. In the absence of rate-regulated accounting, this regulatory balance and the related pension expense would be recorded in earnings and OCI.
7 Regulatory liability related to US income taxes resulted from the US tax reform legislation dated December 22, 2017. This balance will be refunded to customers in accordance with the respective rate settlements approved by the FERC for our US Gas Transmission pipelines and by the respective state utility commission for each US Gas Distribution franchise.
8 Current regulatory liabilities are included in Other current liabilities, while long-term regulatory liabilities are included in Other long-term liabilities.
9 Future removal and site restoration reserves consists of amounts collected from customers, with the approval of the respective regulatory authorities, to fund future costs of removal and site restoration relating to property, plant and equipment. These costs are collected as part of the depreciation expense charged on property, plant and equipment that is reflected in rates. The settlement of this balance will occur over the long-term as costs are incurred. In the absence of rate-regulated accounting, depreciation rates would not include a charge for removal and site restoration and costs would be charged to earnings as incurred with recognition of revenue for amounts previously collected.

8. ACQUISITIONS AND DISPOSITION

BUSINESS COMBINATIONS

We accounted for each of the acquisitions discussed below using the acquisition method as prescribed by ASC 805 *Business Combinations*. In accordance with valuation methodologies described in ASC 820 *Fair Value Measurement,* acquired assets and assumed liabilities are recorded at their estimated fair values as at the date of acquisition.

The fair values of regulatory assets and liabilities, which are subject to rate-setting and cost recovery mechanisms under ASC 980 *Regulated Operations*, are equal to their carrying values at acquisition. The recognition of regulatory assets and liabilities is based on the actions, or expected future actions, of the regulator. To the extent that the regulator's actions differ from our expectations, the timing and amount of recovery or settlement of regulatory balances could differ significantly from those recorded at acquisition.

Public Service Company of North Carolina, Incorporated

On September 30, 2024, through a wholly-owned US subsidiary, we acquired all of the membership interests of Fall North Carolina Holdco LLC, which owns 100% of Public Service Company of North Carolina, Incorporated (PSNC), for cash consideration of $2.7 billion (US$2.0 billion) (the PSNC Acquisition). PSNC is a public utility primarily engaged in the purchase, sale, transportation and distribution of natural gas to residential, commercial and industrial customers in North Carolina. PSNC operates under rates approved by the North Carolina Commission. Subsequent to its acquisition, PSNC conducts business as Enbridge Gas North Carolina.

The following table summarizes the estimated fair values that were assigned to the net assets of PSNC:

	September 30, 2024[1]
(millions of Canadian dollars)	
Fair value of net assets acquired:	
Current assets (a)	303
Property, plant and equipment (b)	4,147
Long-term assets (c)	189
Current liabilities	277
Long-term debt (d)	1,529
Other long-term liabilities (e)	653
Deferred income tax liabilities	365
Goodwill (f)	895
Purchase price:	
Cash	2,710

1 In the fourth quarter of 2024, immaterial adjustments were made to the PSNC Acquisition purchase price allocation.

a) Current assets consist primarily of cash, trade and other accounts receivable, regulatory assets and inventory. The fair value of trade receivables from customers approximates their carrying value of $70 million due to the short period to maturity. A provision of $2 million for expected credit loss associated with accounts receivable has been recorded.

b) PSNC's property, plant and equipment constitutes an integrated system of rate-regulated natural gas transmission, distribution and storage assets. For these rate-regulated assets, fair value was determined using a market participant perspective. Given the regulated nature of, and fixed return on the assets, the fair value of property, plant and equipment acquired is equal to its carrying value.

c) Long-term assets consist primarily of $114 million of regulatory assets expected to be recovered from customers in future periods through rates and equity interests in a liquefied natural gas (LNG) storage facility in North Carolina and in an intrastate natural gas pipeline.

d) The fair value of long-term debt was determined based on the current underlying US Treasury interest rates on instruments of similar yield, credit risk and tenor, as well as an implied credit spread based on current market conditions. We recorded a fair value adjustment to reduce long-term debt by $156 million with no corresponding regulatory offset.

e) Other long-term liabilities consist primarily of regulatory liabilities expected to be refunded to customers in future periods through rates.

f) Goodwill is primarily attributable to the existing assembled assets and workforce of PSNC that cannot be duplicated at the same cost by a new entrant and the enhanced scale and geographic diversity of our regulated natural gas distribution business, which provides a platform for future growth and optimization with existing assets. The goodwill balance recognized has been assigned to our Gas Distribution and Storage segment and is not tax deductible.

Upon completion of the PSNC Acquisition, we began consolidating PSNC. For the period beginning September 30, 2024 through to December 31, 2024, PSNC generated $284 million of operating revenues and $50 million of earnings attributable to common shareholders.

Our supplemental pro forma consolidated financial information for the years ended December 31, 2024 and 2023, including the results of operations for PSNC as if the PSNC Acquisition had been completed on January 1, 2023, is as follows:

Year ended December 31,	2024	2023
(unaudited; millions of Canadian dollars)		
Operating revenues	54,116	44,614
Earnings attributable to common shareholders[1]	5,149	5,944

1 Includes adjustment for pro forma interest expense on debt financing for the PSNC Acquisition of $48 million (after-tax of $37 million) for the year ended December 31, 2023.

Questar Gas Company

On May 31, 2024, through a wholly-owned US subsidiary, we acquired all of the membership interests of Fall West Holdco LLC which owns 100% of Questar and Wexpro for cash consideration of $4.1 billion (US$3.0 billion) (the Questar Acquisition). Questar is a public natural gas utility providing distribution, storage and transmission services to residential, commercial and industrial customers in Utah, southwestern Wyoming and southeastern Idaho. The Utah Commission, the Wyoming Commission and the Idaho Commission have granted Questar the necessary regulatory approvals to serve these areas. Wexpro develops and produces cost-of-service gas reserves for Questar and operates under agreements with the states of Utah and Wyoming. Subsequent to its acquisition, Questar conducts business as Enbridge Gas Utah, Enbridge Gas Wyoming, and Enbridge Gas Idaho in those respective states.

The following table summarizes the estimated fair values that were assigned to the net assets of Questar and Wexpro:

	May 31, 2024[1]
(millions of Canadian dollars)	
Fair value of net assets acquired:	
Current assets (a)	380
Property, plant and equipment (b)	6,013
Long-term assets (c)	163
Current liabilities	416
Long-term debt (d)	1,343
Other long-term liabilities (e)	919
Deferred income tax liabilities	527
Goodwill (f)	793
Purchase price:	
Cash	4,144

1 In the fourth quarter of 2024, immaterial adjustments were made to the Questar Acquisition purchase price allocation.

a) Current assets consist primarily of cash, trade and other accounts receivable and inventory. The fair value of trade receivables from customers approximates their carrying value of $202 million due to the short period to maturity. A provision of $9 million for expected credit loss associated with accounts receivable has been recorded.

b) Questar's property, plant and equipment constitutes an integrated system of rate-regulated natural gas transmission, distribution and storage assets. Wexpro's property, plant and equipment consists of cost-of-service gas and oil properties developed and produced for Questar. For these rate-regulated assets, fair value was determined using a market participant perspective. Given the regulated nature of, and fixed return on the assets, the fair value of property, plant and equipment acquired is equal to its carrying value.

c) Long-term assets consist primarily of funds collected from Questar by Wexpro and held in trust to fund future asset AROs, as well as regulatory assets expected to be recovered from customers in future periods through rates.

d) The fair value of long-term debt was determined based on the current underlying US Treasury interest rates on instruments of similar yield, credit risk and tenor, as well as an implied credit spread based on current market conditions. We recorded a fair value adjustment to reduce long-term debt by $301 million with no corresponding regulatory offset.

e) Other long-term liabilities consist primarily of regulatory liabilities, expected to be refunded to customers in future periods through rates, as well as ARO. The fair value of the ARO liability was determined using a discounted cash flow approach.

f) Goodwill is primarily attributable to the existing assembled assets and workforce of Questar and Wexpro that cannot be duplicated at the same cost by a new entrant and the enhanced scale and geographic diversity of our regulated natural gas distribution business, which provides a platform for future growth and optimization with existing assets. The goodwill balance recognized has been assigned to our Gas Distribution and Storage segment and is not tax deductible.

Upon completion of the Questar Acquisition, we began consolidating Questar and Wexpro. For the period beginning May 31, 2024 through to December 31, 2024, Questar and Wexpro generated $755 million of operating revenues and $75 million of earnings attributable to common shareholders.

Our supplemental pro forma consolidated financial information for the years ended December 31, 2024 and 2023, including the results of operations for Questar and Wexpro as if the Questar Acquisition had been completed on January 1, 2023, is as follows:

Year ended December 31,	2024	2023
(unaudited; millions of Canadian dollars)		
Operating revenues	54,698	45,918
Earnings attributable to common shareholders[1]	5,193	6,005

1 Includes adjustment for pro forma interest expense on debt financing for the Questar Acquisition of $70 million (after-tax of $53 million) for the year ended December 31, 2023.

The East Ohio Gas Company
On March 6, 2024, through a wholly-owned US subsidiary, we acquired all of the outstanding shares of capital stock of the East Ohio Gas Company (EOG) for cash consideration of $5.8 billion (US$4.3 billion) (the EOG Acquisition). EOG is a public natural gas utility providing distribution, storage and transmission services to residential, commercial and industrial customers in Ohio and is regulated by the Ohio Commission. Subsequent to its acquisition, EOG conducts business as Enbridge Gas Ohio.

The following table summarizes the estimated fair values that were assigned to the net assets of EOG:

	March 6, 2024[1]
(millions of Canadian dollars)	
Fair value of net assets acquired:	
Current assets (a)	493
Property, plant and equipment (b)	7,276
Long-term assets (c)	1,689
Current liabilities	551
Long-term debt (d)	2,612
Other long-term liabilities (e)	1,001
Deferred income tax liabilities	1,045
Goodwill (f)	1,603
Purchase price:	
Cash	5,852

1 In the fourth quarter of 2024, immaterial adjustments were made to the EOG Acquisition purchase price allocation.

a) Current assets consist primarily of trade and other accounts receivable, prepaid expenses, regulatory assets and inventory. The fair value of trade receivables from customers approximates their carrying value of $379 million due to the short period to maturity. A provision of $3 million for expected credit loss associated with accounts receivable has been recorded.

b) EOG's property, plant and equipment constitutes an integrated system of rate-regulated natural gas transmission, gathering, distribution and storage assets. For these rate-regulated assets, fair value was determined using a market participant perspective. Given the regulated nature of, and fixed return on the assets, the fair value of property, plant and equipment acquired is equal to its carrying value.

c) Long-term assets consist primarily of overfunded pension plan assets of $367 million and $1.2 billion of regulatory assets expected to be recovered from customers in future periods through rates.

   Pension plan assets attributable to the workforce acquired from EOG were transferred in cash to an Enbridge-sponsored pension plan based on their fair value as at March 6, 2024. The fair value of plan assets was determined using unadjusted quoted market prices for identical investments.

d) The fair value of long-term debt was determined based on the current underlying US Treasury interest rates on instruments of similar yield, credit risk and tenor, as well as an implied credit spread based on current market conditions. We recorded a fair value adjustment to reduce long-term debt by $478 million with no corresponding regulatory offset.

e) Other long-term liabilities consist primarily of regulatory liabilities expected to be refunded to customers in future periods through rates.

f) Goodwill is primarily attributable to the existing assembled assets and workforce of EOG that cannot be duplicated at the same cost by a new entrant and the enhanced scale and geographic diversity of our regulated natural gas distribution business, which provides a platform for future growth and optimization with existing assets. The goodwill balance recognized has been assigned to our Gas Distribution and Storage segment and is not tax deductible.

Upon completion of the EOG Acquisition, we began consolidating EOG. For the period beginning March 6, 2024 through to December 31, 2024, EOG generated $1.2 billion of operating revenues and $190 million of earnings attributable to common shareholders.

Our supplemental pro forma consolidated financial information for the years ended December 31, 2024 and 2023, including the results of operations for EOG as if the EOG Acquisition had been completed on January 1, 2023, was as follows:

Year ended December 31,	2024	2023
(unaudited; millions of Canadian dollars)		
Operating revenues	53,788	45,058
Earnings attributable to common shareholders[1]	5,130	5,961

1 Includes adjustment for pro forma interest expense on debt financing for the EOG Acquisition of $100 million (after-tax of $77 million) for the year ended December 31, 2023.

The PSNC Acquisition, Questar Acquisition and EOG Acquisition (together, the Acquisitions) further diversify, and are complementary to, our existing gas distribution operations.

Acquisition of RNG Facilities
On January 2, 2024, through a wholly-owned US subsidiary, we acquired six Morrow Renewables operating landfill gas-to-RNG production facilities (Tomorrow RNG) located in Texas and Arkansas for total consideration of $1.3 billion (US$1.0 billion), of which $584 million (US$439 million) was paid at close and an additional deferred consideration is payable within two years with a fair value of $757 million (US$568 million) (the RNG Facilities Acquisition). The acquired assets align with and advance our lower-carbon strategy.

The following table summarizes the estimated fair values that were assigned to the net assets of Tomorrow RNG:

	January 2, 2024
(millions of Canadian dollars)	
Fair value of net assets acquired:	
Current assets	31
Intangible assets (a)	925
Property, plant and equipment (b)	174
Current liabilities	5
Goodwill (c)	223
Purchase price:	
Cash	584
Deferred consideration (d):	
Current portion of long-term debt	550
Long-term debt	207
Other adjustments	7
	1,348

a) Intangible assets consist of long-term gas supply agreements with the respective facility's landfill owner. Fair value was determined using an income-based approach, specifically the multi-period excess earnings method, by estimating the present value of the after-tax cash flows attributable to the gas rights. The intangible assets will be amortized on a straight-line basis over the term of the respective agreement, inclusive of extension options, which range from 13 to 42 years (approximately nine years to the next extension period on a weighted-average basis).

b) Tomorrow RNG's property, plant and equipment constitutes specialized landfill gas plant and equipment which collects gas produced by waste decomposition, treats and compresses the gas to pipeline specifications. The direct method of replacement cost was used to determine the majority of the fair value of property, plant and equipment. Adjustments were then applied for estimated physical deterioration.

c) Goodwill is primarily attributable to expected future returns from a portfolio of both operating and scalable RNG assets, furthering the diversity of our renewable projects portfolio and accelerating progress toward our energy transition goals. The goodwill balance recognized has been assigned to our Gas Transmission segment and is tax deductible over 15 years.

d) We entered into six non-interest bearing promissory notes due to Morrow Renewables, the total value of which represents deferred payments of $808 million (US$606 million) due within two years. The first payment was made on January 2, 2025 and the second payment was made on December 31, 2025. The $757 million (US$568 million) recognized in the purchase price represents the fair value of deferred consideration at the date of acquisition using the imputed interest rate method over the terms of the notes.

Upon completion of the RNG Facilities Acquisition, we began consolidating Tomorrow RNG. For the period beginning January 2, 2024 through to December 31, 2024, operating revenues and earnings attributable to common shareholders generated by Tomorrow RNG were immaterial. The impact to our supplemental pro forma consolidated operating revenues and earnings attributable to common shareholders for the years ended December 31, 2024 and 2023, as if the RNG Facilities Acquisition had been completed on January 1, 2023, was also immaterial.

Aitken Creek Gas Storage
On November 1, 2023, through a wholly-owned Canadian subsidiary, we acquired a 93.8% interest in Aitken Creek Gas Storage Facility and a 100% interest in Aitken Creek North Gas Storage Facility (collectively, Aitken Creek), located in BC, Canada, for $400 million (the Aitken Creek Acquisition). Aitken Creek is the only underground natural gas storage facility in BC and connects to all major natural gas pipelines in western Canada. The Aitken Creek Acquisition enables us to continue to meet regional energy needs and to support increasing demand for LNG exports.

The following table summarizes the estimated fair values that were assigned to the net assets of Aitken Creek:

	November 1, 2023
(millions of Canadian dollars)	
Fair value of net assets acquired:	
Current assets (a)	105
Property, plant and equipment (b)	466
Current liabilities	20
Long-term liabilities (c)	130
Goodwill (d)	46
Purchase price:	
Cash	397
Additional consideration (e)	70
	467

a) Current assets consist primarily of inventory which is short-term in nature and represents natural gas held in storage. Fair value was determined using the market price of natural gas at the date of acquisition.

b) Aitken Creek's property, plant and equipment constitutes an integrated system of cavern storage facilities, associated header pipeline, and land and right-of-ways. The depreciated replacement cost approach was adopted as the primary valuation methodology to determine the fair value of property, plant and equipment, excluding the reservoir storage asset. In determining replacement cost, both indirect costing using relevant inflation indices and direct costing using relevant market quotes were utilized. Adjustments were then applied for physical deterioration as well as functional and economic obsolescence.

   Fair value of the reservoir storage asset was determined using a residual approach whereby the adjusted purchase price was allocated to the fair value of the net tangible assets, excluding the reservoir storage asset, with the remaining value allocated to the reservoir storage asset. The income approach was also utilized to corroborate that the cash flows attributable to the reservoir storage asset support the residual value.

c) Long-term liabilities consist primarily of a deferred income tax liability arising from temporary differences between the tax bases of assets and liabilities and their carrying values for accounting purposes at the date of acquisition.

d) Goodwill is primarily attributable to the recognition of a deferred income tax liability. The goodwill balance recognized has been assigned to our Gas Transmission segment and is not tax deductible.

e) The $70 million of additional consideration recognized in the purchase price represents the fair value of derivative contracts and working gas as at March 31, 2023.

Upon completion of the Aitken Creek Acquisition, we began consolidating Aitken Creek. For the period beginning November 1, 2023 through to December 31, 2023, operating revenues and earnings attributable to common shareholders generated by Aitken Creek were immaterial. The impact to our supplemental pro forma consolidated operating revenues and earnings attributable to common shareholders for the year ended December 31, 2023, as if the Aitken Creek Acquisition had been completed on January 1, 2022, was also immaterial.

NONCONTROLLING INTEREST INVESTMENT
Westcoast Energy Limited Partnership
On July 1, 2025, Westcoast completed a reorganization in which substantially all of the property and assets relating to the BC Pipeline system were transferred to a newly formed partnership, Westcoast LP. On July 2, 2025, the First Nations Partnership invested approximately $736 million to subscribe for all of the Class A units of Westcoast LP, resulting in a 12.50% interest in the partnership. The cash consideration of $736 million and a respective Redeemable NCI based on the consideration received less transaction costs were recorded in the Consolidated Statements of Financial Position on close, to reflect the interest held by the First Nations Partnership.

We continue to manage and operate the BC Pipeline system. Refer to *Note 12 - Variable Interest Entities* and *Note 19 - Noncontrolling Interests*.

ASSET ACQUISITION
Tres Palacios Holdings LLC
On April 3, 2023, we acquired Tres Palacios Holdings LLC (Tres Palacios) for $451 million (US$335 million) of cash. Tres Palacios owns and operates a natural gas storage facility located in the US Gulf Coast and its infrastructure serves Texas gas-fired power generation and LNG exports, as well as Mexico pipeline exports.

We allocated assets with a fair value of $790 million (US$588 million) to Property, plant and equipment, net, of which $254 million (US$189 million) relates to storage cavern right-of-use assets, and recorded the related lease liabilities of $7 million (US$5 million) and $248 million (US$184 million) to Current portion of long-term debt and Long-term debt, respectively, in the Consolidated Statements of Financial Position. The acquired assets are included in our Gas Transmission segment.

9. OTHER CURRENT ASSETS

December 31,	**2025**	2024
(millions of Canadian dollars)		
Gas imbalances	**705**	517
Regulatory assets *(Note 7)*	**694**	472
Derivative assets *(Note 23)*	**591**	557
Income taxes receivable	**346**	375
Other	**894**	849
	3,230	2,770

10. INVENTORY

December 31,	**2025**	2024
(millions of Canadian dollars)		
Natural gas	**901**	811
Crude oil	**548**	479
Other	**172**	198
	1,621	1,488

11. PROPERTY, PLANT AND EQUIPMENT

December 31,	Weighted Average Depreciation Rate	2025	2024
(millions of Canadian dollars)			
Pipelines	2.8 %	**72,233**	73,633
Facilities and equipment	3.2 %	**44,101**	43,439
Land and right-of-way[1]	2.9 %	**4,330**	4,181
Gas mains, services and other	3.0 %	**27,927**	26,925
Storage	2.5 %	**6,673**	6,455
Wind turbines, solar panels and other	3.4 %	**5,818**	4,798
Other	9.3 %	**4,416**	3,987
Under construction	— %	**7,240**	5,648
Total property, plant and equipment[2]		**172,738**	169,066
Total accumulated depreciation[2]		**(41,140)**	(37,962)
Property, plant and equipment, net		**131,598**	131,104

1 The measurement of weighted average depreciation rate excludes non-depreciable assets.
2 As at December 31, 2025, the cost and accumulated depreciation of leased assets accounted for as lessor operating leases was $4.7 billion and $2.1 billion, respectively (December 31, 2024 - $4.7 billion and $2.0 billion, respectively).

Depreciation expense for the years ended December 31, 2025, 2024 and 2023 was $5.1 billion, $4.6 billion and $4.0 billion, respectively.

12. VARIABLE INTEREST ENTITIES

WESTCOAST ENERGY LIMITED PARTNERSHIP

Westcoast LP is a BC limited partnership which holds and operates our Westcoast BC Pipeline system, serving customers in western Canada and the US Pacific Northwest. The limited partners, Westcoast and the First Nations Partnership, hold 87.52% and 12.47% interests in Westcoast LP, respectively. The remaining 0.01% general partner interest is held by Westcoast Energy GP Inc., our wholly-owned subsidiary.

Westcoast LP is considered a VIE as its limited partners lack substantive participating rights and kick-out rights. In addition to having the obligation to absorb losses and the right to expected returns, we, through our direct interests and the operating agreement between Westcoast and Westcoast LP, have the ability to direct the activities of Westcoast LP's principal operations, thereby making us the primary beneficiary of the VIE. Westcoast LP is a consolidated VIE of Enbridge.

CONSOLIDATED VARIABLE INTEREST ENTITIES

Our consolidated VIEs consist of legal entities of which we are the primary beneficiary. We are the primary beneficiary when our variable interest(s) provide(s) us with (i) the power to direct the activities of the VIE that most significantly impact the entity's economic performance and (ii) the obligation to absorb losses, or the right to receive benefits, from the VIE that could potentially be significant to the VIE. We determine whether we are the primary beneficiary of a VIE by considering qualitative and quantitative factors, including, but not limited to: decision-making responsibilities, the VIE capital structure, risk and reward sharing, contractual agreements with the VIE, voting rights and level of involvement of other parties.

The following table includes assets only to be used to settle the liabilities of our consolidated VIEs. The creditors of the liabilities of our consolidated VIEs do not have recourse to us as the primary beneficiary. These assets and liabilities are included in the Consolidated Statements of Financial Position.

December 31,	**2025**	2024
(millions of Canadian dollars)		
Assets		
Current assets		
Cash and cash equivalents	**681**	448
Restricted cash	**15**	11
Trade receivables and unbilled revenues	**221**	138
Other current assets	**31**	5
Accounts receivable from affiliates	**50**	13
Inventory	**45**	13
	1,043	628
Property, plant and equipment, net	**12,543**	6,934
Long-term investments	**2**	20
Restricted long-term investments and cash	**308**	141
Deferred amounts and other assets	**171**	145
Intangible assets, net	**83**	77
	14,150	7,945
Liabilities		
Current liabilities		
Trade payables and accrued liabilities	**325**	108
Other current liabilities	**144**	124
Accounts payable to affiliates	**1**	22
	470	254
Other long-term liabilities	**1,293**	1,133
Deferred income taxes	**9**	6
	1,772	1,393
	12,378	6,552

On July 2, 2025, we entered into a credit agreement with Westcoast LP, pursuant to which we provided a one-year non-revolving term credit facility of up to $100 million. As at December 31, 2025, there have been no funds drawn on the credit facility. We did not provide, and did not have obligations to provide, additional financial support to any of our other consolidated VIEs.

UNCONSOLIDATED VARIABLE INTEREST ENTITIES

We also hold interests in unconsolidated VIEs where we are not the primary beneficiary as we do not have the power to direct the activities of the VIEs that most significantly impact the entity's economic performance. These interests include investments in limited partnerships that are assessed to be VIEs due to the limited partners not having substantive participating rights or kick-out rights. The power to direct the activities of a majority of these unconsolidated limited partnership VIEs is shared amongst the partners. Each partner has representatives that make up an executive committee that makes significant decisions for the VIE and none of the partners may make significant decisions unilaterally.

The carrying amount of these VIEs and our estimated maximum exposure to loss as at December 31, 2025 and 2024 are as follows:

December 31, 2025	Carrying Amount of the VIE	Maximum Exposure to Loss
(millions of Canadian dollars)		
Rampion Offshore Wind Limited[1]	**365**	**408**
Vector Pipeline[2]	**179**	**295**
Woodfibre LNG Limited Partnership[3]	**2,081**	**4,490**
Whistler Parent JV[4]	**949**	**1,001**
Other[3]	**187**	**1,364**
	3,761	**7,558**

December 31, 2024	Carrying Amount of the VIE	Maximum Exposure to Loss
(millions of Canadian dollars)		
Rampion Offshore Wind Limited[1]	387	490
Vector Pipeline[2]	193	314
Woodfibre LNG Limited Partnership[3]	1,275	3,153
Whistler Parent JV[4]	1,102	1,425
Other[3]	168	501
	3,125	5,883

1 As at December 31, 2025 and 2024, our maximum exposure to loss includes parental guarantees that have been committed in project contracts in which we would be liable for in the event of default by the VIE and the carrying value of an affiliate dividend receivable of nil and $73 million, respectively.

2 Includes Vector Pipeline Limited Partnership in Canada and Vector Pipeline L.P. in the US. As at December 31, 2025 and 2024, our maximum exposure to loss includes the carrying value of outstanding affiliate loans receivable of $11 million and $16 million, respectively, and our share of the VIE's available credit facility for $105 million.

3 Our maximum exposure to loss includes parental guarantees and funding obligations that have been committed in connection with the projects for which we would be liable in the event of default by the VIE(s).

4 Our maximum exposure to loss included funding obligations that have been committed in project contracts in which we would be liable for in the event of default by the VIE.

With respect to our equity investment in Woodfibre LNG Limited Partnership, we provide certain construction and operational guarantees. Although some guarantees do not contain contractual limitations on potential future payments, our undiscounted estimated maximum exposure to loss related to these guarantees as at December 31, 2025 is approximately $2.4 billion (2024 - $1.9 billion). Construction guarantees expire upon completion of the related construction activities. Operational guarantees are expected to expire over a period ranging from 17 to 42 years. Certain of these guarantees also include contractual indemnification rights that allow us to recover amounts paid under the guarantees from other project participants. These indemnification rights are separate from, and legally independent of, our guarantee obligations.

We did not provide, and did not have obligations to provide, financial support to our unconsolidated VIEs during the years ended December 31, 2025 and 2024. For details on guarantee arrangements entered into with our VIEs refer to *Note 31 - Guarantees.*

13. LONG-TERM INVESTMENTS

December 31,	Ownership Interest	**2025**	2024
(millions of Canadian dollars)			
EQUITY INVESTMENTS			
Liquids Pipelines			
Cactus II Pipeline LLC	30.0%	**594**	651
DCP Midstream, LLC (Class B Units)[1]	90.0%	**1,437**	1,554
Illinois Extension Pipeline Company, L.L.C.	65.0%	**566**	608
MarEn Bakken Company LLC[2]	75.0%	**2,090**	2,296
Seaway Crude Holdings LLC	50.0%	**2,630**	2,820
Other	30.0%–62.5%	**173**	96
Gas Transmission			
DCP Midstream, LLC (Class A Units)[3]	23.4%	**736**	480
Delaware Basin Residue, LLC[4]	15.0%	**320**	319
Gulfstream Natural Gas System, L.L.C.	50.0%	**1,240**	1,316
Matterhorn Express Pipeline[5]	10.0%	**454**	—
NEXUS Gas Transmission, LLC	50.0%	**1,223**	1,301
Sabal Trail Transmission, LLC	50.0%	**1,456**	1,565
Southeast Supply Header, LLC	50.0%	**348**	355
Steckman Ridge, LP	50.0%	**104**	101
Vector Pipeline	60.0%	**179**	193
Whistler Parent JV[6]	19.0%	**949**	1,102
Woodfibre LNG Limited Partnership	30.0%	**2,081**	1,275
Offshore - various joint ventures	22.0%–74.3%	**294**	260
Other	21.3%–24.8%	**18**	49
Gas Distribution and Storage			
Other	17.0%–50.0%	**66**	67
Renewable Power Generation			
East-West Tie Limited Partnership[7]	24.1%	**—**	106
EIH S.à r.l.[8]	51.0%	**156**	89
Fox Squirrel Solar LLC	50.0%	**723**	783
Hohe See and Albatros Offshore Wind Facilities	49.9%	**1,641**	1,606
Rampion Offshore Wind Limited	24.9%	**365**	387
Other	16.4%–50.0%	**87**	93
OTHER LONG-TERM INVESTMENTS			
Gas Transmission		**139**	139
Gas Distribution and Storage		**25**	27
Renewable Power Generation		**21**	21
Eliminations and Other[9]		**1,149**	1,032
		21,264	20,691

1 *We own 90.0% of the Class B units of DCP Midstream, LLC. This class of units represents DCP Midstream, LLC's 65.0% interest in Gray Oak Pipeline, LLC (Gray Oak), resulting in a 58.5% interest in Gray Oak through DCP Midstream, LLC. We also have an additional 10.0% direct interest in Gray Oak, bringing our effective interest in Gray Oak to 68.5%.*

2 *We own 75.0% of MarEn Bakken Company LLC, which owns a 49.0% interest in Bakken Pipeline Investments LLC. Bakken Pipeline Investments LLC owns 75.0% of the Bakken Pipeline System, resulting in a 27.6% effective interest in the Bakken Pipeline System held by us. We provide a financing guarantee for certain debt obligations. Our undiscounted maximum exposure to loss related to this guarantee as at December 31, 2025, is approximately $320 million (2024 - $337 million). The guarantee expires in 2029.*

3 *We own 23.4% of the Class A units of DCP Midstream, LLC. These units represent DCP Midstream, LLC's 56.5% interest in DCP Midstream, LP (DCP), resulting in a 13.2% effective interest in DCP held by us.*

4 *On October 31, 2024, we acquired an effective 15.0% interest in Delaware Basin Residue, LLC for consideration of $303 million (US$220 million).*

5 *On June 16, 2025, we acquired a 10% non-operating equity interest in Matterhorn Express natural gas pipeline for $413 million (US$302 million).*

6 *On May 29, 2024, we formed a joint venture with WhiteWater/I Squared Capital and MPLX LP. We hold a 19.0% interest in the joint venture, which owns a 100% interest in the Rio Bravo Pipeline project.*

7 *On March 4, 2025, we closed the sale of our 24.1% equity interest in the East-West Tie Limited Partnership for $130 million.*

8 *EIH S.à r.l. owns a 50.0% interest in Éolien Maritime France SAS (EMF). Through our investment in EMF, we own equity interests in three French offshore wind projects, including effective interests in Saint-Nazaire (25.5%), Fécamp (17.9%) and Courseulles (Calvados) (21.7%).*

9 *Consists of investments in debt securities held by our wholly-owned captive insurance subsidiary. Refer to* Note 23 - Risk Management and Financial Instruments.

Equity investments include the unamortized excess of the purchase price over the underlying net book value of the investees' assets at the purchase date. As at December 31, 2025, this basis difference was $3.9 billion (2024 - $3.7 billion), of which $1.8 billion (2024 - $1.7 billion) was amortizable.

For the years ended December 31, 2025, 2024 and 2023, distributions received from equity investments were $2.7 billion, $2.9 billion and $3.1 billion, respectively, which are reported within Operating activities and Investing activities in the Consolidated Statements of Cash Flows.

Summarized combined financial information of our unconsolidated equity investments (presented at 100%) is as follows:

Year ended December 31,	**2025**	2024	2023
(millions of Canadian dollars)			
Operating revenues	**23,721**	20,657	22,586
Operating expenses	**16,860**	14,692	17,111
Earnings	**6,346**	5,177	4,818
Earnings attributable to Enbridge	**2,224**	2,304	1,816

December 31,	**2025**	2024
(millions of Canadian dollars)		
Current assets	**8,503**	8,611
Non-current assets	**72,855**	69,381
Current liabilities	**5,049**	7,240
Non-current liabilities	**30,800**	27,491
Noncontrolling interests	**5,564**	4,979

DISPOSITION

Disposition of Alliance Pipeline and Aux Sable Interests

On April 1, 2024, we closed the sale of our 50.0% interest in the Alliance Pipeline, our interest in Aux Sable and our interest in NRGreen Power Limited Partnership (NRGreen) to Pembina Pipeline Corporation for $3.1 billion, including $327 million of non-recourse debt. A gain on disposal of $1.1 billion before tax, which is net of $1.0 billion of the goodwill from our Gas Transmission segment allocated to the disposal group, is included in Gain on disposition of equity investments in the Consolidated Statements of Earnings for the year ended December 31, 2024. Our equity investments in the Alliance Pipeline and Aux Sable were previously included in our Gas Transmission segment. Our equity investment in NRGreen was previously included in our Renewable Power Generation segment.

OTHER EQUITY INVESTMENT TRANSACTIONS

Joint Venture with WhiteWater/I Squared and MPLX

On May 29, 2024, we formed a joint venture (the Whistler Parent JV) with WhiteWater/I Squared Capital (WhiteWater/I Squared) and MPLX LP (MPLX) that will develop, construct, own and operate natural gas pipeline and storage assets connecting Permian Basin natural gas supply to growing LNG and other US Gulf Coast demand. The Whistler Parent JV is owned by WhiteWater/I Squared (50.6%), MPLX (30.4%) and Enbridge (19.0%) and is accounted for as an equity method investment.

In connection with the formation of the Whistler Parent JV, we contributed our 100% interest in the Rio Bravo Pipeline project and $487 million (US$357 million) of cash to the Whistler Parent JV. In addition to our 19.0% equity interest in the Whistler Parent JV, we received a special equity interest in the Whistler Parent JV which provides for a 25.0% economic interest in the Rio Bravo Pipeline project. This interest is subject to certain redemption rights held by the Whistler Parent JV, which was redeemed on July 17, 2025 for net proceeds of $180 million (US$130 million). After the closing on May 29, 2024, we accrued for our share of the post-closing mandatory capital expenditures of approximately US$150 million for the Rio Bravo Pipeline project.

The contribution of our interest in the Rio Bravo Pipeline project to the Whistler Parent JV in exchange for the equity interests discussed above represents a non-cash transaction in Cash Flows from Investing Activities and does not have an effect on our Consolidated Statements of Cash Flows. This component of the transaction resulted in a reduction of $321 million (US$235 million) to Property, plant and equipment, net and a corresponding increase to Long-term investments in the Consolidated Statements of Financial Position. The cash component of the transaction, as well as subsequent cash payments made for post-closing mandatory capital expenditures, have been reflected as contributions in Cash Flows from Investing Activities.

14. INTANGIBLE ASSETS

December 31, 2025	Weighted Average Amortization Rate	Cost	Accumulated Amortization	Net
(millions of Canadian dollars)				
Software	10.3%	**1,980**	**(1,244)**	**736**
Power purchase agreements	4.5%	**58**	**(29)**	**29**
Project agreement[1]	4.0%	**164**	**(56)**	**108**
Customer relationships	8.6%	**2,730**	**(1,168)**	**1,562**
Biogas rights agreements[2]	3.3%	**952**	**(64)**	**888**
Other intangible assets	6.2%	**674**	**(277)**	**397**
Under development	—%	**271**	**—**	**271**
		6,829	**(2,838)**	**3,991**

December 31, 2024	Weighted Average Amortization Rate	Cost	Accumulated Amortization	Net
(millions of Canadian dollars)				
Software	10.9%	2,109	(1,222)	887
Power purchase agreements	4.5%	58	(26)	32
Project agreement[1]	4.0%	173	(52)	121
Customer relationships	8.6%	2,856	(975)	1,881
Biogas rights agreements[2]	3.4%	999	(34)	965
Other intangible assets	5.8%	665	(234)	431
Under development	—%	270	—	270
		7,130	(2,543)	4,587

1 Represents a project agreement acquired from the merger of Enbridge and Spectra Energy.
2 Biogas rights agreements are amortized on a straight-line basis over the term of the respective agreement, inclusive of extension options, which range from 12 to 41 years (approximately seven years to the next extension period on a weighted-average basis).

For the years ended December 31, 2025, 2024 and 2023, our amortization expense related to intangible assets totaled $534 million, $530 million and $535 million, respectively. Our expected amortization expense associated with existing intangible assets for each of the years 2026 to 2030 is $520 million.

15. GOODWILL

	Liquids Pipelines	Gas Transmission	Gas Distribution and Storage	Renewable Power Generation	Consolidated
(millions of Canadian dollars)					
Balance at January 1, 2024	8,344	17,727	5,397	380	31,848
Dispositions[3]	—	(1,026)	—	—	(1,026)
Foreign exchange and other	672	1,354	204	34	2,264
Acquisition[4]	—	223	3,291	—	3,514
Balance at December 31, 2024[1,2]	9,016	18,278	8,892	414	36,600
Foreign exchange and other	**(379)**	**(747)**	**(171)**	**(19)**	**(1,316)**
Balance at December 31, 2025[1,2]	**8,637**	**17,531**	**8,721**	**395**	**35,284**

1 *Gross goodwill as at December 31, 2025 and 2024 was $39.4 billion and $40.7 billion, respectively.*
2 *Accumulated impairment as at December 31, 2025 and 2024 was $4.1 billion.*
3 *In 2024, we derecognized $1.0 billion of goodwill related to the sale of our interests in the Alliance Pipeline and Aux Sable. Refer to* Note 13 - Long-Term Investments.
4 *In 2024, we recorded $895 million of goodwill related to the PSNC Acquisition, $793 million of goodwill related to the Questar Acquisition, $1.6 billion of goodwill related to the EOG Acquisition, and $223 million of goodwill related to the RNG Facilities Acquisition. Refer to* Note 8 - Acquisitions and Disposition.

16. OTHER CURRENT LIABILITIES

December 31,	**2025**	2024
(millions of Canadian dollars)		
Dividends payable	**2,150**	2,088
Deferred credits	**1,214**	1,072
Taxes payable	**901**	959
Derivative liabilities *(Note 23)*	**712**	1,335
Regulatory liabilities *(Note 7)*	**533**	616
Affiliate note payable *(Note 29)*	**228**	172
Asset retirement obligations *(Note 18)*	**113**	120
Federal carbon program liability	**—**	498
Other	**323**	381
	6,174	7,241

17. DEBT

December 31,	Weighted Average Interest Rate[8]	Maturity	**2025**	2024
(millions of Canadian dollars)				
Enbridge Inc.				
US dollar senior notes	5.0%	2026 - 2054	**22,550**	19,703
Medium-term notes	4.6%	2026 - 2064	**11,719**	9,900
Sustainability-linked bonds	4.7%	2032 - 2033	**6,924**	7,146
Fixed-to-fixed subordinated term notes[1]	7.2%	2054 - 2084	**10,015**	9,372
Fixed-to-floating rate subordinated term notes[2]	5.8%	2077 - 2078	**5,964**	6,139
Floating rate notes[3]		2028	**400**	—
Commercial paper and credit facility draws	3.0%	2027 - 2049	**6,488**	5,843
Other[4]			**24**	12
Enbridge (U.S.) Inc.				
Commercial paper and credit facility draws	4.1%	2027 - 2030	**4,636**	4,707
Other[4]			**528**	276
Enbridge Energy Partners, L.P.				
Senior notes	6.7%	2026 - 2045	**2,673**	3,524
Enbridge Gas Inc.				
Medium-term notes	4.2%	2026 - 2055	**10,150**	9,970
Debentures		2025	**—**	125
Commercial paper and credit facility draws	2.4%	2027	**1,030**	530
Other[4]			**—**	1
Enbridge Pipelines (Southern Lights) LLC				
Senior notes	4.0%	2040	**618**	736
Enbridge Pipelines Inc.				
Medium-term notes	4.3%	2026 - 2053	**4,725**	5,425
Commercial paper and credit facility draws	2.7%	2027	**1,024**	509
Other[4]			**—**	2
Enbridge Southern Lights LP				
Senior notes	4.0%	2040	**168**	183
Spectra Energy Capital, LLC				
Senior notes	7.1%	2032 - 2038	**237**	248
Algonquin Gas Transmission, LLC				
Senior notes	4.4%	2029 - 2034	**1,165**	1,222
East Tennessee Natural Gas, LLC				
Senior notes	5.7%	2034	**631**	662
Texas Eastern Transmission, LP				
Senior notes	4.7%	2028 - 2048	**3,496**	3,667
Spectra Energy Partners, LP				
Senior notes	4.4%	2026 - 2045	**2,330**	3,164
Blauracke GmbH				
Senior notes	2.1%	2032	**446**	471
The East Ohio Gas Company				
Senior notes	4.3%	2030 - 2056	**3,701**	3,308
Other[4]			**23**	24
Questar Gas Company				
Senior notes	4.2%	2027 - 2052	**1,933**	2,028
Public Service Co. of North Carolina				
Senior notes	4.8%	2026	**1,576**	1,654
Debentures	7.2%	2028 - 2054	**137**	144
Enbridge Holdings (Tomorrow RNG), LLC				
Senior notes			**—**	817
Westcoast Energy Inc.				
Medium-term notes	6.2%	2027 - 2041	**550**	875
Debentures	7.3%	2026	**125**	275
Other[4]			**2**	—
Fair value adjustment			**(430)**	(468)
Other[5]			**(534)**	(522)
Total debt[6]			**105,024**	101,672
Current maturities			**(5,031)**	(7,729)
Short-term borrowings[7]			**(1,030)**	(529)
Long-term debt			**98,963**	93,414

1 For an initial five, 5.25, 5.5, 9.75 or 10 years, the notes carry a fixed interest rate. Subsequently, during each reset period the interest rate will be reset to equal to the Five-Year US Treasury Rate or Five-Year Government of Canada bond yield plus a margin. The notes would be converted automatically into Conversion Preference Shares in the event of bankruptcy and related events.
2 For an initial five or 10 years, the notes carry a fixed interest rate. Subsequently, the interest rate converts to a floating rate. The notes would be converted automatically into Conversion Preference Shares in the event of bankruptcy and related events.
3 Notes carry an interest rate set to equal the Canadian Overnight Repo Rate Average plus a margin of 85 basis points.
4 Primarily finance lease obligations.
5 Primarily unamortized discounts, premiums and debt issuance costs.
6 2025 - $43 billion, US$45 billion and €277 million; 2024 - $40 billion, US$43 billion and €316 million. Totals exclude finance lease obligations, unamortized discounts, premiums and debt issuance costs and fair value adjustment.
7 Weighted average interest rates on outstanding commercial paper were 2.4% as at December 31, 2025 (2024 - 3.4%).
8 Calculated based on term notes, debentures, commercial paper and credit facility draws outstanding as at December 31, 2025.

As at December 31, 2025, all outstanding debt was unsecured.

CREDIT FACILITIES

The following table provides details of our committed credit facilities as at December 31, 2025:

	Maturity[1]	Total Facility	Draws[2]	Available
(millions of Canadian dollars)				
Enbridge Inc.	2027-2049	**8,033**	**6,488**	**1,545**
Enbridge (U.S.) Inc.	2027-2030	**10,307**	**4,636**	**5,671**
Enbridge Pipelines Inc.	2027	**2,000**	**1,024**	**976**
Enbridge Gas Inc.	2027	**2,500**	**1,030**	**1,470**
Total committed credit facilities		**22,840**	**13,178**	**9,662**

1 Maturity date is inclusive of the one-year term out option for certain credit facilities.
2 Includes facility draws and commercial paper issuances that are back-stopped by credit facilities.

In July 2025, we renewed approximately $8.8 billion of our 364-day extendible credit facilities, extending the maturity dates to July 2027, which includes a one-year term out provision from July 2026. We also renewed approximately $7.8 billion of our five-year credit facilities, extending the maturity dates to July 2030. Further, we extended the maturity dates of our three-year credit facilities to July 2028.

In July 2025, Enbridge Gas Ontario and Enbridge Pipelines Inc. extended the maturity dates of their $2.5 billion and $2.0 billion 364-day extendible credit facilities, respectively, to July 2027, which includes a one-year term out provision from July 2026.

In addition to the committed credit facilities noted above, we maintain $1.6 billion of uncommitted demand letter of credit facilities, of which $932 million was unutilized as at December 31, 2025. As at December 31, 2024, we had $1.4 billion of uncommitted demand letter of credit facilities, of which $931 million was unutilized.

Our credit facilities carry a weighted average standby fee of 0.1% per annum on the unused portion and draws bear interest at market rates. Certain credit facilities serve as a back-stop to our commercial paper programs and we have the option to extend such facilities, which are currently scheduled to mature from 2027 to 2049.

As at December 31, 2025 and December 31, 2024, commercial paper and credit facility draws, net of short-term borrowings and non-revolving credit facilities that mature within one year, of $12.1 billion and $10.3 billion, respectively, were supported by the availability of long-term committed credit facilities and, therefore, have been classified as long-term debt.

LONG-TERM DEBT ISSUANCES

During the year ended December 31, 2025, we completed the following long-term debt issuances totaling $4.6 billion and US$4.7 billion:

Company	Issuance Date			Principal Amount
(millions of Canadian dollars, unless otherwise stated)				
Enbridge Inc.				
	February 2025	Floating rate	medium-term notes due February 2028[1]	$400
	February 2025	3.55%	medium-term notes due February 2028	$300
	February 2025	3.90%	medium-term notes due February 2030	$800
	February 2025	4.56%	medium-term notes due February 2035	$700
	February 2025	5.32%	medium-term notes due August 2054	$600
	June 2025	4.60%	senior notes due June 2028	US$400
	June 2025	4.90%	senior notes due June 2030	US$600
	June 2025	5.55%	senior notes due June 2035	US$900
	June 2025	5.95%	senior notes due April 2054	US$350
	September 2025	5.15%	fixed-to-fixed subordinated notes due December 2055[2]	$1,000
	November 2025	4.20%	senior notes due November 2028	US$500
	November 2025	4.50%	senior notes due February 2031	US$500
	November 2025	5.20%	senior notes due November 2035	US$500
Enbridge Gas Inc.				
	September 2025	4.16%	medium-term notes due September 2035	$500
	September 2025	4.84%	medium-term notes due September 2055	$300
The East Ohio Gas Company				
	June 2025	5.68%	senior notes due June 2035	US$250
	June 2025	6.32%	senior notes due June 2055	US$250
	December 2025	5.23%	senior notes due March 2036	US$250
	December 2025	5.95%	senior notes due March 2056	US$150

1 Notes carry an interest rate set to equal the Canadian Overnight Repo Rate Average plus a margin of 85 basis points.

2 For the initial 5.25 years, the notes carry a fixed interest rate. On December 17, 2030, the interest rate will be reset to equal the Five-Year Government of Canada bond yield plus a margin of 2.39%.

LONG-TERM DEBT REPAYMENTS

During the year ended December 31, 2025, we completed the following long-term debt repayments totaling US$3.1 billion, $2.5 billion and €39 million:

Company	Repayment Date			Principal Amount
(millions of Canadian dollars, unless otherwise stated)				
Enbridge Inc.				
	January 2025	2.50%	senior notes	US$500
	February 2025	2.50%	senior notes	US$500
	June 2025	2.44%	medium-term notes	$550
Enbridge Gas Inc.				
	September 2025	3.31%	medium-term notes	$400
	September 2025	3.19%	medium-term notes	$200
	October 2025	8.85%	medium-term notes	$20
	November 2025	8.65%	debentures	$125
Enbridge Pipelines (Southern Lights) L.L.C.				
	June and December 2025	3.98%	senior notes	US$61
Enbridge Pipelines Inc.				
	February 2025	4.10%	medium-term notes[1]	$100
	September 2025	3.45%	medium-term notes	$600
Enbridge Southern Lights LP				
	June and December 2025	4.01%	senior notes	$15
Westcoast Energy Inc.				
	July 2025	8.85%	debentures	$150
	November 2025	8.80%	medium-term notes	$25
	December 2025	3.77%	medium-term notes	$300
Enbridge Energy Partners, L.P.				
	July 2025	5.88%	senior notes[2]	US$500
Spectra Energy Partners, LP				
	March 2025	3.50%	senior notes	US$500
Blauracke GmbH				
	April and October 2025	2.10%	senior notes	€39
Enbridge Holdings (Tomorrow RNG), LLC				
	January 2025	4.97%	senior notes	US$309
	January 2025	4.97%	senior notes	US$85
	January 2025	4.97%	senior notes	US$19
	December 2025	4.80%	senior notes	US$7
	December 2025	4.80%	senior notes	US$90
	December 2025	4.80%	senior notes	US$58
The East Ohio Gas Company				
	June 2025	1.30%	senior notes	US$500

1 The notes carried an original maturity date in July 2112.
2 The notes carried an original maturity date in October 2025.

DEBT COVENANTS

Our credit facility agreements and term debt indentures include standard events of default and covenant provisions whereby accelerated repayment and/or termination of the agreements may result if we were to default on payment or violate certain covenants. As at December 31, 2025, we were in compliance with all such debt covenant provisions.

ANNUAL DEBT MATURITIES

As at December 31, 2025, we have commitments as detailed below:

	Total	Less than 1 year	2 years	3 years	4 years	5 years	Thereafter
(millions of Canadian dollars)							
Annual debt maturities[1]	104,410	4,988	8,995	4,900	5,704	12,584	67,239

1 Includes debentures, term notes, commercial paper and credit facility draws based on the facility's maturity date and excludes short-term borrowings, unamortized discounts, premiums, debt issuance costs, finance lease obligations and fair value adjustment. We have the ability under certain debt facilities to call and repay the obligations prior to scheduled maturities. Therefore, the actual timing of future cash repayments could be materially different than presented above.

INTEREST EXPENSE

Year ended December 31,	**2025**	2024	2023
(millions of Canadian dollars)			
Debentures and term notes	**4,688**	4,123	3,439
Commercial paper and credit facility draws	**559**	439	519
Amortization of fair value adjustment	**31**	18	(45)
Capitalized interest	**(255)**	(161)	(101)
	5,023	4,419	3,812

18. ASSET RETIREMENT OBLIGATIONS

Our ARO relate mostly to the retirement of pipelines, renewable power generation assets, oil and gas wells and production facilities, and obligations related to right-of way agreements and contractual leases for land use.

The discount rates used to estimate the present value of the expected future cash flows for the year ended December 31, 2025 ranged from 3.0% to 9.0% and for the year ended December 31, 2024 ranged from 1.5% to 9.0%.

A reconciliation of movements in our ARO liabilities is as follows:

December 31,	**2025**	2024
(millions of Canadian dollars)		
Obligations at beginning of year	**666**	493
Liabilities acquired	**—**	185
Liabilities incurred	**368**	3
Liabilities settled	**(56)**	(139)
Change in estimate and other	**48**	51
Foreign currency translation adjustment	**(23)**	40
Accretion expense	**29**	33
Obligations at end of year	**1,032**	666
Presented as follows:		
Other current liabilities *(Note 16)*	**113**	120
Other long-term liabilities	**919**	546
	1,032	666

19. NONCONTROLLING INTERESTS

The following table provides additional information regarding Noncontrolling interests as presented in our Consolidated Statements of Financial Position:

December 31,	**2025**	2024
(millions of Canadian dollars)		
Enbridge Athabasca Midstream Investor Limited Partnership	**1,052**	1,073
Renewable energy assets	**744**	786
Maritimes & Northeast Pipeline, L.L.C.	**562**	606
Algonquin Gas Transmission, LLC	**390**	414
Maritimes & Northeast Pipeline Limited Partnership	**106**	109
Other	**1**	5
	2,855	2,993

REDEEMABLE NONCONTROLLING INTEREST

Westcoast Energy Limited Partnership

The First Nations Partnership's Class A units are classified as Redeemable NCI within the mezzanine equity section of the Consolidated Statements of Financial Position. As at December 31, 2025, the outstanding Class B and Class C units are held by us.

The First Nations Partnership is required to fund a minimum amount for capital costs related to other than designated capital programs, however, they may elect to fund up to their pro-rata share should it be higher than the minimum amount. Class A and Class B units are issued to the First Nations Partnership and us, respectively, in exchange for this funding.

The changes in our Redeemable NCI were as follows:

Year ended December 31,	**2025**
(millions of Canadian dollars)	
Balance at beginning of year	**—**
Proceeds from investment by redeemable noncontrolling interest in subsidiary	**736**
Transaction costs, net of deferred tax benefit	**(27)**
Earnings attributable to redeemable noncontrolling interest	**28**
Distributions declared to unitholder	**(35)**
Contributions from unitholder	**6**
Redemption value adjustment	**28**
Balance at end of year	**736**

The First Nations Partnership's ownership percentage decreased from 12.50% on transaction close to 12.47% as at December 31, 2025, as a result of contributing less than their pro-rata share of capital costs for other than designated capital programs.

20. SHARE CAPITAL

Our authorized share capital consists of an unlimited number of common shares with no par value and an unlimited number of preference shares.

	2025		2024		2023	
December 31,	Number of Shares	Amount	Number of Shares	Amount	Number of Shares	Amount
(millions of Canadian dollars; number of shares in millions)						
Balance at beginning of year	**2,178**	**71,738**	2,125	69,180	2,025	64,760
Shares issued, net of issue costs and tax	**—**	**—**	51	2,489	103	4,485
Shares issued on exercise of stock options	**3**	**89**	1	39	—	3
Shares issued on vesting of RSUs	**1**	**49**	1	30	—	12
Share repurchases at stated value[1]	**—**	**—**	—	—	(3)	(80)
Balance at end of year	**2,182**	**71,876**	2,178	71,738	2,125	69,180

1 Reflects the repurchase and cancellation of common shares under our normal course issuer bid.

On May 15, 2024, we filed prospectus supplements in Canada and the US to establish an at-the-market equity issuance program (the ATM Program) that allowed us to issue and sell, at our discretion, up to $2.75 billion (or the US dollar equivalent) of our common shares from treasury to the public from time to time at the market prices prevailing at the time of sale through the Toronto Stock Exchange, the New York Stock Exchange (NYSE) or any other marketplace in Canada or the US where the common shares may be traded.

During the period from May 15, 2024 to July 31, 2024, 51,298,629 common shares were issued and sold under the ATM Program at average prices of CAD$48.72 and US$35.77 per common share for aggregate gross proceeds of $2.50 billion ($2.48 billion, net of aggregate commissions paid of $16.3 million and other issuance costs). On August 1, 2024, we terminated the ATM Program. Net proceeds from sales of common shares under the ATM Program were used to partially fund the Questar Acquisition and PSNC Acquisition and to pay related fees and expenses.

On September 8, 2023, we closed a public offering of 102,913,500 common shares at a price of $44.70 per share for gross proceeds of $4.6 billion which were also used to finance a portion of the aggregate cash consideration payable for the Acquisitions discussed in *Note 8 - Acquisitions and Disposition*.

PREFERENCE SHARES

December 31,	**2025** Number of Shares	**2025** Amount	2024 Number of Shares	2024 Amount	2023 Number of Shares	2023 Amount
(millions of Canadian dollars; number of shares in millions)						
Preference Shares, Series A	**5**	**125**	5	125	5	125
Preference Shares, Series B	**20**	**500**	20	500	20	500
Preference Shares, Series D	**18**	**450**	18	450	18	450
Preference Shares, Series F	**18**	**454**	18	454	18	454
Preference Shares, Series G	**2**	**46**	2	46	2	46
Preference Shares, Series H	**12**	**291**	12	291	12	291
Preference Shares, Series I	**2**	**59**	2	59	2	59
Preference Shares, Series L	**16**	**411**	16	411	16	411
Preference Shares, Series N	**18**	**450**	18	450	18	450
Preference Shares, Series P	**16**	**400**	16	400	16	400
Preference Shares, Series R	**16**	**400**	16	400	16	400
Preference Shares, Series 1	**16**	**411**	16	411	16	411
Preference Shares, Series 3	**22**	**562**	22	562	24	600
Preference Shares, Series 4[1]	**2**	**38**	2	38	—	—
Preference Shares, Series 5	**8**	**206**	8	206	8	206
Preference Shares, Series 7	**10**	**250**	10	250	10	250
Preference Shares, Series 9	**11**	**275**	11	275	11	275
Preference Shares, Series 11	**20**	**500**	20	500	20	500
Preference Shares, Series 13	**14**	**350**	14	350	14	350
Preference Shares, Series 15	**11**	**275**	11	275	11	275
Preference Shares, Series 19	**20**	**500**	20	500	20	500
Issuance costs		**(135)**		(135)		(135)
Balance at end of year		**6,818**		6,818		6,818

1 On September 1, 2024, 1,502,775 of the outstanding Preference Shares, Series 3 were converted into Preference Shares, Series 4.

Characteristics of our outstanding preference shares are as follows:

	Dividend Rate	Dividend[1]	Per Share Base Redemption Value[2,3]	Redemption and Conversion Option Date[2,3]	Right to Convert Into[3,4]
(Canadian dollars unless otherwise stated)					
Preference Shares, Series A	5.50%	$1.37500	$25	—	—
Preference Shares, Series B	5.20%	$1.30050	$25	June 1, 2027	Series C
Preference Shares, Series D	5.41%	$1.35300	$25	March 1, 2028	Series E
Preference Shares, Series F	5.54%	$1.38450	$25	June 1, 2028	Series G
Preference Shares, Series G[5]	4.84%	$1.21000	$25	June 1, 2028	Series F
Preference Shares, Series H	6.11%	$1.52800	$25	September 1, 2028	Series I
Preference Shares, Series I[6]	4.45%	$1.11250	$25	September 1, 2028	Series H
Preference Shares, Series L	5.86%	US$1.46448	US$25	September 1, 2027	Series M
Preference Shares, Series N	6.70%	$1.67400	$25	December 1, 2028	Series O
Preference Shares, Series P	5.92%	$1.47950	$25	March 1, 2029	Series Q
Preference Shares, Series R	6.31%	$1.57850	$25	June 1, 2029	Series S
Preference Shares, Series 1	6.70%	US$1.67593	US$25	June 1, 2028	Series 2
Preference Shares, Series 3	5.29%	$1.32200	$25	September 1, 2029	Series 4
Preference Shares, Series 4[7]	4.71%	$1.17750	$25	September 1, 2029	Series 3
Preference Shares, Series 5	6.68%	US$1.67075	US$25	March 1, 2029	Series 6
Preference Shares, Series 7	5.99%	$1.49700	$25	March 1, 2029	Series 8
Preference Shares, Series 9	5.67%	$1.41800	$25	December 1, 2029	Series 10
Preference Shares, Series 11[8]	5.48%	$1.36925	$25	March 1, 2030	Series 12
Preference Shares, Series 13[9]	5.40%	$1.34875	$25	June 1, 2030	Series 14
Preference Shares, Series 15[10]	5.63%	$1.40650	$25	September 1, 2030	Series 16
Preference Shares, Series 19	6.21%	$1.55300	$25	March 1, 2028	Series 20

1 The holder is entitled to receive a fixed cumulative quarterly preferential dividend, as declared by the Board of Directors. With the exception of Preference Shares, Series A, such fixed dividend rate resets every five years beginning on the initial Redemption and Conversion Option Date. Preference Shares, Series G, Series I and Series 4 contain a feature where the dividend rate resets on a quarterly basis. The Preference Shares, Series 19 contain a feature where the fixed dividend rate, when reset every five years, will not be less than 4.90%. No other series of preference shares has this feature.

2 Preference Shares, Series A may be redeemed any time at our option. For all other series of preference shares, we may at our option, redeem all or a portion of the outstanding preference shares for the Per Share Base Redemption Value plus all accrued and unpaid dividends on the Redemption Option Date and on every fifth anniversary thereafter.

3 The holder will have the right, subject to certain conditions, to convert their shares into Cumulative Redeemable Preference Shares of a specified series on a one-for-one basis on the Conversion Option Date and every fifth anniversary thereafter at an ascribed issue price equal to the Per Share Base Redemption Value.

4 With the exception of Preference Shares, Series A, after the Redemption and Conversion Option Date, holders may elect to receive quarterly floating rate cumulative dividends per share at a rate equal to: $25 x (number of days in quarter/number of days in year) x three-month Government of Canada treasury bill rate + 2.4% (Series C), 2.4% (Series E), 2.5% (Series G), 2.1% (Series I), 2.7% (Series O), 2.5% (Series Q), 2.5% (Series S), 2.4% (Series 4), 2.6% (Series 8), 2.7% (Series 10), 2.6% (Series 12), 2.7% (Series 14), 2.7% (Series 16), or 3.2% (Series 20); or US$25 x (number of days in quarter/number of days in year) x three-month US Government treasury bill rate + 3.2% (Series M), 3.1% (Series 2), or 2.8% (Series 6).

5 The quarterly dividend per share paid on Preference Shares, Series G was decreased to $0.29836 from $0.32411 on December 1, 2025 due to reset on a quarterly basis.

6 The quarterly dividend per share paid on Preference Shares, Series I was decreased to $0.27432 from $0.29980 on December 1, 2025 due to reset on a quarterly basis.

7 The quarterly dividend per share paid on Preference Shares, Series 4 was decreased to $0.29034 from $0.31601 on December 1, 2025 due to reset on a quarterly basis.

8 The quarterly dividend per share paid on Preference Shares, Series 11 was increased to $0.34231 from $0.24613 on March 1, 2025,due to the reset of the annual dividend on March 1, 2025.

9 The quarterly dividend per share paid on Preference Shares, Series 13 was increased to $0.33719 from $0.19019 on June 1, 2025 due to the reset of the annual dividend on June 1, 2025.

10 The quarterly dividend per share paid on Preference Shares, Series 15 was increased to $0.35163 from $0.18644 on September 1, 2025 due to the reset of the annual dividend on September 1, 2025.

SHAREHOLDER RIGHTS PLAN

The Shareholder Rights Plan is designed to encourage the fair treatment of our shareholders in connection with any takeover offer. Rights issued under the plan become exercisable when a person and any related parties acquires or announces its intention to acquire 20% or more of our outstanding common shares without complying with certain provisions set out in the plan or without approval of our Board of Directors. Should such an acquisition occur, each rights holder, other than the acquiring person and related parties, will have the right to purchase our common shares at a 50% discount to the market price at that time.

21. STOCK OPTION AND STOCK UNIT PLANS

We maintain three primary vehicles under our long-term incentive plan (the Plan): ISOs, PSUs and RSUs. Total stock-based compensation expense recorded for the years ended December 31, 2025, 2024 and 2023 was $285 million, $186 million and $154 million, respectively. The number of common shares authorized for share-settled awards under the Plan was 181 million as at December 31, 2025, 2024 and 2023.

INCENTIVE STOCK OPTIONS

Certain key employees are granted ISOs to purchase common shares at the grant date market price. ISOs vest in equal annual installments over a four-year period and expire 10 years after the issue date.

December 31, 2025	Number	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life *(years)*	Aggregate Intrinsic Value
(number of options in thousands; weighted average exercise price in Canadian dollars; intrinsic value in millions of Canadian dollars)				
Options outstanding at beginning of year	**25,324**	**50.31**		
Options granted	**3,146**	**60.13**		
Options exercised[1]	**(10,200)**	**51.03**		
Options cancelled or expired	**(584)**	**56.25**		
Options outstanding at end of year	**17,686**	**51.45**	**6.3**	**214**
Options vested at end of year[2]	**8,780**	**50.17**	**4.7**	**116**

1 The total intrinsic value of ISOs exercised during the years ended December 31, 2025, 2024 and 2023 was $123 million, $18 million and $2 million, respectively, and cash received on exercise was $28 million, $1 million and nil, respectively.

2 The total fair value of ISOs vested during the years ended December 31, 2025, 2024 and 2023 was $17 million, $17 million and $20 million, respectively.

Weighted average assumptions used to determine the fair value of ISOs granted using the Black-Scholes-Merton model are as follows:

Year ended December 31,	**2025**	2024	2023
Fair value per option *(Canadian dollars)*[1]	**6.97**	4.07	6.05
Valuation assumptions			
Expected option term *(years)*[2]	**6**	6	6
Expected volatility[3]	**21.2%**	21.1%	22.2%
Expected dividend yield[4]	**6.3%**	8.1%	6.7%
Risk-free interest rate[5]	**3.6%**	3.8%	3.5%

1 Options granted to US employees are based on the NYSE prices. The option value and assumptions shown are based on a weighted average of the US and Canadian options. The fair value per option for the years ended December 31, 2025, 2024 and 2023 were $5.76, $3.53 and $5.38, respectively, for Canadian employees and US$5.88, US$3.58 and US$5.23, respectively, for US employees.
2 The expected option term is six years based on historical exercise practice and five years for retirement eligible employees.
3 Expected volatility is determined with reference to historic daily share price volatility and consideration of the implied volatility observable in call option values near the grant date.
4 The expected dividend yield is the current annual dividend at the grant date divided by the current stock price.
5 The risk-free interest rate is based on the Government of Canada's Canadian bond yields and the US Treasury bond yields at the grant date.

Compensation expense recorded for the years ended December 31, 2025, 2024 and 2023 for ISOs was $21 million, $19 million and $18 million, respectively. As at December 31, 2025, unrecognized compensation expense related to non-vested ISOs was $12 million. The expense is expected to be fully recognized over a weighted average period of approximately two years.

PERFORMANCE STOCK UNITS

PSUs are granted to certain key employees where cash awards are paid following a three-year performance cycle. Awards are calculated by multiplying the number of units outstanding at the end of the performance period by Enbridge's weighted average share price for 20 days prior to the maturity of the grant and by a performance multiplier. The performance multiplier ranges from zero, if our performance fails to meet threshold performance levels, to a maximum of 2.0 if we perform within the highest range of the performance targets. The performance multiplier is derived through a calculation of our Total Shareholder Return percentile rank relative to a specified peer group of companies and our distributable cash flow per share, adjusted for unusual, infrequent or other non-operating factors, relative to targets established at the time of grant, as well as a greenhouse gas reduction component. To calculate the 2025 expense, a multiplier of 1.68 was used for 2025 PSU grants, 1.82 for 2024 PSU grants and 1.32 for 2023 PSU grants.

December 31, 2025	Number	Weighted Average Remaining Contractual Life *(years)*	Aggregate Intrinsic Value
(number of units in thousands; intrinsic value in millions of Canadian dollars)			
Units outstanding at beginning of year	**3,402**		
Units granted	**1,071**		
Units cancelled	**(101)**		
Units matured[1]	**(938)**		
Dividend reinvestment	**195**		
Units outstanding at end of year	**3,629**	**1.9**	**386**

1 The total amount paid during the years ended December 31, 2025, 2024 and 2023 for PSUs was $60 million, $65 million and $123 million, respectively.

Compensation expense recorded for the years ended December 31, 2025, 2024 and 2023 for PSUs was $164 million, $75 million and $59 million, respectively. As at December 31, 2025, unrecognized compensation expense related to non-vested PSUs was $100 million. The expense is expected to be fully recognized over a weighted average period of approximately one-and-a-half years.

RESTRICTED STOCK UNITS

Employees may also be granted cash-settled or share-settled RSUs under the Plan. Share-settled awards granted to non-executive senior management employees vest following a three-year maturity period. Share-settled units are also granted to non-executive employees and vest either on each of the first, second and third anniversaries of the grant date, or following a 12-month period. Cash-settled RSUs are given to non-executive employees and are paid in equal installments on each of the first, second and third anniversaries of the grant date.

RSU holders receive cash or shares equal to Enbridge's weighted average share price for 20 days prior to the maturity of the grant multiplied by the number of units outstanding on the maturity date.

December 31, 2025	Number	Weighted Average Grant Date Fair Value[1]	Weighted Average Remaining Contractual Life *(years)*	Aggregate Intrinsic Value
(number of units in thousands; intrinsic value in millions of Canadian dollars)				
Units outstanding at beginning of year	**3,591**	**51.10**		
Units granted	**1,435**	**59.30**		
Units cancelled or expired	**(130)**	**52.98**		
Units matured[2]	**(1,680)**	**50.95**		
Dividend reinvestment	**212**	**52.60**		
Units outstanding at end of year	**3,428**	**53.54**	**0.9**	**184**

1 Weighted average grant date fair value excludes cash-settled units.
2 The total amount paid during the years ended December 31, 2025, 2024 and 2023 for RSUs was $23 million, $40 million and $56 million, respectively.

Compensation expense recorded for the years ended December 31, 2025, 2024 and 2023 for RSUs was $100 million, $92 million and $77 million, respectively. As at December 31, 2025, unrecognized compensation expense related to non-vested RSUs was $63 million. The expense is expected to be fully recognized over a weighted average period of approximately one-and-a-half years.

22. COMPONENTS OF ACCUMULATED OTHER COMPREHENSIVE INCOME

Changes in AOCI attributable to our common shareholders for the years ended December 31, 2025, 2024 and 2023 are as follows:

	Cash Flow Hedges	Excluded Components of Fair Value Hedges	Net Investment Hedges	Cumulative Translation Adjustment	Equity Investees and Other Investments	Pension and OPEB Adjustment	Total
(millions of Canadian dollars)							
Balance as at January 1, 2025	**407**	**(14)**	**(2,033)**	**8,452**	**1**	**302**	**7,115**
Other comprehensive income/(loss) retained in AOCI	**46**	**12**	**419**	**(3,080)**	**23**	**237**	**(2,343)**
Other comprehensive (income)/loss reclassified to earnings							
Interest rate contracts[1]	**30**	**—**	**—**	**—**	**—**	**—**	**30**
Foreign exchange contracts[2]	**—**	**(3)**	**—**	**—**	**—**	**—**	**(3)**
Amortization of pension and OPEB actuarial gain[3]	**—**	**—**	**—**	**—**	**—**	**(39)**	**(39)**
	76	**9**	**419**	**(3,080)**	**23**	**198**	**(2,355)**
Tax impact							
Income tax on amounts retained in AOCI	**(18)**	**4**	**—**	**—**	**1**	**(73)**	**(86)**
Income tax on amounts reclassified to earnings	**(3)**	**1**	**—**	**—**	**—**	**9**	**7**
	(21)	**5**	**—**	**—**	**1**	**(64)**	**(79)**
Balance as at December 31, 2025	**462**	**—**	**(1,614)**	**5,372**	**25**	**436**	**4,681**

	Cash Flow Hedges	Excluded Components of Fair Value Hedges	Net Investment Hedges	Cumulative Translation Adjustment	Equity Investees and Other Investments	Pension and OPEB Adjustment	Total
(millions of Canadian dollars)							
Balance as at January 1, 2024	320	(23)	(728)	2,653	11	70	2,303
Other comprehensive income/(loss) retained in AOCI	79	(42)	(1,305)	5,799	(9)	323	4,845
Other comprehensive (income)/loss reclassified to earnings							
Interest rate contracts[1]	31	—	—	—	—	—	31
Commodity contracts[4]	(1)	—	—	—	—	—	(1)
Foreign exchange contracts[2]	—	53	—	—	—	—	53
Amortization of pension and OPEB actuarial gain[3]	—	—	—	—	—	(21)	(21)
	109	11	(1,305)	5,799	(9)	302	4,907
Tax impact							
Income tax on amounts retained in AOCI	(15)	10	—	—	(1)	(75)	(81)
Income tax on amounts reclassified to earnings	(7)	(12)	—	—	—	5	(14)
	(22)	(2)	—	—	(1)	(70)	(95)
Balance as at December 31, 2024	407	(14)	(2,033)	8,452	1	302	7,115

	Cash Flow Hedges	Excluded Components of Fair Value Hedges	Net Investment Hedges	Cumulative Translation Adjustment	Equity Investees and Other Investments	Pension and OPEB Adjustment	Total
(millions of Canadian dollars)							
Balance as at January 1, 2023	121	(35)	(1,137)	4,348	5	218	3,520
Other comprehensive income/(loss) retained in AOCI	232	62	409	(1,695)	6	(158)	(1,144)
Other comprehensive (income)/loss reclassified to earnings							
Interest rate contracts[1]	28	—	—	—	—	—	28
Foreign exchange contracts[2]	—	(47)	—	—	—	—	(47)
Amortization of pension and OPEB actuarial gain[3]	—	—	—	—	—	(24)	(24)
	260	15	409	(1,695)	6	(182)	(1,187)
Tax impact							
Income tax on amounts retained in AOCI	(47)	(14)	—	—	—	28	(33)
Income tax on amounts reclassified to earnings	(14)	11	—	—	—	6	3
	(61)	(3)	—	—	—	34	(30)
Balance as at December 31, 2023	320	(23)	(728)	2,653	11	70	2,303

1 Reported within Interest expense in the Consolidated Statements of Earnings.
2 Reported within Interest expense and Other income/(expense) in the Consolidated Statements of Earnings.
3 These components are included in the computation of net periodic benefit credit and are reported within Other income/(expense) in the Consolidated Statements of Earnings.
4 Reported within Transportation and other services revenues in the Consolidated Statements of Earnings.

23. RISK MANAGEMENT AND FINANCIAL INSTRUMENTS

MARKET RISK

Our earnings, cash flows and OCI are subject to movements in foreign exchange rates, interest rates, commodity prices and our share price (collectively, market risks). Formal risk management policies, processes and systems have been designed to mitigate these risks.

The following summarizes the types of market risks to which we are exposed and the risk management instruments used to mitigate them. We use a combination of qualifying and non-qualifying derivative instruments to manage the risks noted below.

Foreign Exchange Risk

We generate certain revenues, incur expenses and hold a number of investments and subsidiaries that are denominated in currencies other than Canadian dollars. As a result, our earnings, cash flows and OCI are exposed to fluctuations resulting from foreign exchange rate variability.

We employ financial derivative instruments to hedge foreign currency denominated earnings exposure. A combination of qualifying and non-qualifying derivative instruments is used to hedge anticipated foreign currency denominated revenues and expenses and to manage variability in cash flows. We hedge certain net investments in US dollar-denominated investments and subsidiaries using US dollar-denominated debt.

Interest Rate Risk

Our earnings, cash flows and OCI are exposed to short-term interest rate variability due to the regular repricing of our variable rate debt, primarily commercial paper. We have a policy of limiting the maximum floating rate debt to 30% of total debt outstanding. We monitor and adjust our debt portfolio mix of fixed and variable rate debt instruments, along with the use of derivative instruments, to support compliance with our policy. We have implemented a program to partially mitigate the impact of short-term interest rate volatility on interest expense via the execution of floating-to-fixed interest rate swaps and costless collars. These swaps have an average fixed rate of 2.8%.

We are exposed to changes in the fair value of fixed rate debt that arise as a result of changes in market interest rates. Pay floating-receive fixed interest rate swaps are used, when applicable, to hedge against future changes to the fair value of fixed rate debt which mitigates the impact of fluctuations in fair value. Executed fixed-to-floating interest rate swaps have an average swap rate of 2.8%.

Our earnings and cash flows are also exposed to variability in longer term interest rates ahead of anticipated fixed rate term debt issuances. A combination of qualifying and non-qualifying forward starting interest rate swaps are used to hedge against the effect of future interest rate movements. We have established a program including some of our subsidiaries to partially mitigate our exposure to long-term interest rate variability on forecasted term debt issuances via execution of floating-to-fixed interest rate swaps with an average swap rate of 3.4%.

Commodity Price Risk
Our earnings, cash flows and OCI are exposed to changes in commodity prices as a result of our ownership interests in certain assets and investments, as well as through the activities of our energy marketing subsidiaries. These commodities include natural gas, crude oil, power and NGL. We employ financial and physical derivative instruments to fix a portion of the variable price exposures that arise from physical transactions involving these commodities. For our US Gas Utilities, changes in derivatives' fair values are deferred as regulatory assets or liabilities until settlement. We use primarily non-qualifying derivative instruments to manage commodity price risk.

Equity Price Risk
Equity price risk is the risk of earnings fluctuations due to changes in our share price. We have exposure to our own common share price through the issuance of various forms of stock-based compensation, which affect earnings through the revaluation of outstanding units every period.

TOTAL DERIVATIVE INSTRUMENTS
We have a policy of entering into individual International Swaps and Derivatives Association, Inc. (ISDA) agreements, or other similar derivative agreements, with the majority of our financial derivative counterparties. These agreements provide for the net settlement of derivative instruments outstanding with specific counterparties in the event of bankruptcy or other significant credit events and reduce our credit risk exposure on financial derivative asset positions in those circumstances.

The following tables summarize the Consolidated Statements of Financial Position location and carrying value of our derivative instruments, as well as the maximum potential settlement amounts, in the event of the specific circumstances described above.

December 31, 2025	Derivative Instruments Used as Cash Flow Hedges	Derivative Instruments Used as Fair Value Hedges	Non-Qualifying Derivative Instruments	Total Gross Derivative Instruments as Presented	Amounts Available for Offset	Total Net Derivative Instruments
(millions of Canadian dollars)						
Other current assets						
Foreign exchange contracts	**—**	**—**	**27**	**27**	**(17)**	**10**
Interest rate contracts	**79**	**5**	**22**	**106**	**(37)**	**69**
Commodity contracts	**—**	**—**	**458**	**458**	**(192)**	**266**
	79	**5**	**507**	**591**	**(246)**	**345**
Deferred amounts and other assets						
Foreign exchange contracts	**—**	**—**	**52**	**52**	**(24)**	**28**
Interest rate contracts	**9**	**—**	**108**	**117**	**(27)**	**90**
Commodity contracts	**—**	**—**	**124**	**124**	**(20)**	**104**
	9	**—**	**284**	**293**	**(71)**	**222**
Other current liabilities						
Foreign exchange contracts	**—**	**—**	**(364)**	**(364)**	**17**	**(347)**
Interest rate contracts	**(9)**	**—**	**(39)**	**(48)**	**37**	**(11)**
Commodity contracts	**—**	**—**	**(300)**	**(300)**	**192**	**(108)**
	(9)	**—**	**(703)**	**(712)**	**246**	**(466)**
Other long-term liabilities						
Foreign exchange contracts	**—**	**—**	**(819)**	**(819)**	**24**	**(795)**
Interest rate contracts	**—**	**(34)**	**(50)**	**(84)**	**27**	**(57)**
Commodity contracts	**—**	**—**	**(92)**	**(92)**	**20**	**(72)**
	—	**(34)**	**(961)**	**(995)**	**71**	**(924)**
Total net derivative asset/(liability)						
Foreign exchange contracts	**—**	**—**	**(1,104)**	**(1,104)**	**—**	**(1,104)**
Interest rate contracts	**79**	**(29)**	**41**	**91**	**—**	**91**
Commodity contracts	**—**	**—**	**190**	**190**	**—**	**190**
	79	**(29)**	**(873)**	**(823)**	**—**	**(823)**

December 31, 2024	Derivative Instruments Used as Cash Flow Hedges	Derivative Instruments Used as Fair Value Hedges	Non-Qualifying Derivative Instruments	Total Gross Derivative Instruments as Presented	Amounts Available for Offset	Total Net Derivative Instruments
(millions of Canadian dollars)						
Other current assets						
Foreign exchange contracts	—	78	47	125	(29)	96
Interest rate contracts	44	—	23	67	(39)	28
Commodity contracts	2	—	360	362	(191)	171
Other contracts	—	—	3	3	—	3
	46	78	433	557	(259)	298
Deferred amounts and other assets						
Foreign exchange contracts	—	—	83	83	(71)	12
Interest rate contracts	9	—	137	146	(27)	119
Commodity contracts	—	—	197	197	(39)	158
	9	—	417	426	(137)	289
Other current liabilities						
Foreign exchange contracts	—	(73)	(731)	(804)	29	(775)
Interest rate contracts	(58)	—	(22)	(80)	39	(41)
Commodity contracts	—	—	(451)	(451)	191	(260)
	(58)	(73)	(1,204)	(1,335)	259	(1,076)
Other long-term liabilities						
Foreign exchange contracts	—	—	(1,579)	(1,579)	71	(1,508)
Interest rate contracts	—	—	(80)	(80)	27	(53)
Commodity contracts	(1)	—	(238)	(239)	39	(200)
	(1)	—	(1,897)	(1,898)	137	(1,761)
Total net derivative asset/(liability)						
Foreign exchange contracts	—	5	(2,180)	(2,175)	—	(2,175)
Interest rate contracts	(5)	—	58	53	—	53
Commodity contracts	1	—	(132)	(131)	—	(131)
Other contracts	—	—	3	3	—	3
	(4)	5	(2,251)	(2,250)	—	(2,250)

The following table summarizes the maturity and notional principal or quantity outstanding related to our derivative instruments:

	2025							2024
As at December 31,	2026	2027	2028	2029	2030	Thereafter	Total	Total
Foreign exchange contracts - US dollar forwards - purchase *(millions of US dollars)*	**1,027**	**—**	**—**	**—**	**—**	**—**	**1,027**	1,245
Foreign exchange contracts - US dollar forwards - sell *(millions of US dollars)*	**6,406**	**5,321**	**4,332**	**2,358**	**1,110**	**360**	**19,887**	21,614
Foreign exchange contracts - US dollar collars - sell *(millions of US dollars)*	**180**	**180**	**120**	**—**	**—**	**—**	**480**	—
Foreign exchange contracts - British pound (GBP) forwards - sell *(millions of GBP)*	**28**	**32**	**—**	**—**	**—**	**—**	**60**	90
Foreign exchange contracts - Euro forwards - sell *(millions of Euro)*	**121**	**81**	**67**	**66**	**65**	**64**	**464**	590
Foreign exchange contracts - Japanese yen forwards - purchase *(millions of yen)*	**—**	**—**	**—**	**—**	**—**	**—**	**—**	84,800
Interest rate contracts - short-term pay fixed rate *(millions of Canadian dollars)*	**3,897**	**2,846**	**2,220**	**1,003**	**—**	**—**	**9,966**	4,771
Interest rate contracts - receive fixed rate *(millions of Canadian dollars)*	**1,500**	**1,500**	**1,500**	**1,500**	**1,500**	**5,816**	**13,316**	—
Interest rate contracts - long-term pay fixed rate *(millions of Canadian dollars)*[1]	**4,204**	**468**	**—**	**—**	**—**	**—**	**4,672**	5,284
Interest rate contracts - costless collar *(millions of Canadian dollars)*	**1,955**	**1,823**	**77**	**—**	**—**	**—**	**3,855**	2,316
Commodity contracts - natural gas *(billions of cubic feet)*[2]	**123**	**66**	**29**	**12**	**6**	**—**	**236**	288
Commodity contracts - crude oil *(millions of barrels)*[2]	**(5)**	**13**	**1**	**1**	**1**	**—**	**11**	25
Commodity contracts - power *(megawatt per hour (MW/H))*	**145**	**85**	**55**	**29**	**(2)**	**(2)**	**34**[3]	(5)[3]

1 Represents the notional amount of long-term debt issuances hedged.
2 Represents the notional amount of net purchase/(sale).
3 Total is an average net purchase/(sale) of power.

Derivatives Designated as Fair Value Hedges
The following table presents interest rate and foreign exchange derivative instruments that are designated and qualify as fair value hedges. The realized and unrealized gain or loss on the derivative is included in Other income/ (expense) or Interest expense in the Consolidated Statements of Earnings. The offsetting loss or gain on the hedged item attributable to the hedged risk is included in Other income/(expense) or Interest expense in the Consolidated Statements of Earnings. Any excluded components are included in the Consolidated Statements of Comprehensive Income.

Year ended December 31,	**2025**	2024
(millions of Canadian dollars)		
Unrealized loss on derivative	**(43)**	(3)
Unrealized gain on hedged item	**28**	6
Realized gain on derivative	**25**	26
Realized loss on hedged item	**(23)**	(79)

The Effect of Derivative Instruments on the Statements of Earnings and Comprehensive Income
The following table presents the effect of cash flow hedges and fair value hedges on our consolidated earnings and comprehensive income, before the effect of income taxes:

Year ended December 31,	**2025**	2024	2023
(millions of Canadian dollars)			
Amount of unrealized gain/(loss) recognized in OCI			
Cash flow hedges			
Interest rate contracts	**46**	67	201
Commodity contracts	**—**	19	68
Other contracts	**—**	1	(2)
Fair value hedges			
Foreign exchange contracts	**12**	(42)	15
	58	45	282
Amount of (income)/loss reclassified from AOCI to earnings			
Foreign exchange contracts[1]	**(3)**	53	—
Interest rate contracts[2]	**30**	31	28
Commodity contracts[3]	**—**	(1)	—
	27	83	28

1 Reported within Interest expense and Other income/(expense) in the Consolidated Statements of Earnings.
2 Reported within Interest expense in the Consolidated Statements of Earnings.
3 Reported within Transportation and other services revenues in the Consolidated Statements of Earnings.

We estimate that a gain of $9 million from AOCI related to cash flow hedges will be reclassified to earnings in the next 12 months. Actual amounts reclassified to earnings depend on the foreign exchange rates, interest rates and commodity prices in effect when derivative contracts that are currently outstanding mature. For all forecasted transactions, the maximum term over which we are hedging exposures to the variability of cash flows is two years as at December 31, 2025.

Non-Qualifying Derivatives

The following table presents the unrealized gains and losses associated with changes in the fair value of our non-qualifying derivatives:

Year ended December 31,	**2025**	2024	2023
(millions of Canadian dollars)			
Foreign exchange contracts[1]	**1,076**	(2,033)	1,292
Interest rate contracts[2]	**(17)**	112	(63)
Commodity contracts[3]	**322**	(53)	(41)
Other contracts[4]	**(3)**	2	(8)
Total unrealized derivative fair value gain/(loss), net	**1,378**	(1,972)	1,180

1 *For the respective years ended, reported within Transportation and other services revenues (2025 - nil; 2024 - nil; 2023 - $645 million gain) and Other income/(expense) (2025 - $1.1 billion loss; 2024 - $2 billion loss; 2023 - $647 million gain) in the Consolidated Statements of Earnings.*

2 *Reported within Interest expense in the Consolidated Statements of Earnings.*

3 *For the respective years ended, reported within Transportation and other services revenues (2025 - $102 million gain; 2024 - $23 million loss; 2023 - $35 million loss), Commodity sales (2025 - $34 million loss; 2024 - $92 million loss; 2023 - $153 million gain), Commodity costs (2025 - $190 million gain; 2024 - $31 million loss; 2023 - $94 million loss), Operating and administrative expense (2025 - $20 million gain; 2024 - $17 million loss; 2023 - $65 million loss) in the Consolidated Statements of Earnings. The fair value change in our US Gas Utilities is deferred as regulatory assets/(liabilities) (2025 - $44 million gain; 2024 - $110 million gain; 2023 - nil).*

4 *Reported within Operating and administrative expense in the Consolidated Statements of Earnings.*

LIQUIDITY RISK

Liquidity risk is the risk that we will not be able to meet our financial obligations, including commitments and guarantees, as they become due. In order to mitigate this risk, we forecast cash requirements over a 12-month rolling time period to determine whether sufficient funds will be available. Our primary sources of liquidity and capital resources are funds generated from operations, the issuance of commercial paper and draws under committed credit facilities and long-term debt, which includes debentures and medium-term notes. Our shelf prospectuses with securities regulators enable ready access to either the Canadian or US public capital markets, subject to market conditions. In addition, we maintain sufficient liquidity through committed credit facilities with a diversified group of banks and institutions which, if necessary, enables us to fund all anticipated requirements for approximately one year without accessing the capital markets. We were in compliance with all the terms and conditions of our committed credit facility agreements and term debt indentures as at December 31, 2025. As a result, all credit facilities are available to us and the banks are obligated to fund us under the terms of the facilities. We also identify other potential sources of debt and equity funding alternatives, including reinstatement of our dividend reinvestment and share purchase plan or at-the-market equity issuances.

CREDIT RISK

Entering into derivative instruments may result in exposure to credit risk from the possibility that a counterparty will default on its contractual obligations. In order to mitigate this risk, we enter into risk management transactions primarily with institutions that possess strong investment grade credit ratings. Credit risk relating to derivative counterparties is mitigated through the maintenance and monitoring of credit exposure limits, contractual requirements and netting arrangements. We also review counterparty financial strength using external credit rating services and other analytical tools to manage credit risk.

We have credit concentrations and credit exposure, with respect to derivative instruments, in the following counterparty segments:

December 31,	**2025**	2024
(millions of Canadian dollars)		
Canadian financial institutions	**200**	344
US financial institutions	**260**	128
European financial institutions	**57**	116
Asian financial institutions	**39**	53
Other[1]	**302**	332
	858	973

1 Other is comprised of commodity clearing house and crude oil, natural gas and power counterparties.

As at December 31, 2025, we did not provide any letters of credit in lieu of providing cash collateral to our counterparties pursuant to the terms of the relevant ISDA agreements. We held no cash collateral on derivative asset exposures as at December 31, 2025 and December 31, 2024.

Gross derivative balances have been presented without the effects of collateral posted. Derivative assets are adjusted for non-performance risk of our counterparties using their credit default swap spread rates and are reflected at fair value. For derivative liabilities, our non-performance risk is considered in the valuation.

Credit risk also arises from trade and other long-term receivables, and is mitigated through credit exposure limits and contractual requirements, the assessment of counterparty credit ratings and netting arrangements. Within the Gas Distribution and Storage segment, credit risk is mitigated by the large and diversified customer base and the ability to recover expected credit losses through the ratemaking process. We actively monitor the financial strength of large industrial customers and, in select cases, have obtained additional security to minimize the risk of default on receivables. Generally, we utilize a loss allowance matrix which contemplates historical credit losses by age of receivables, adjusted for any forward-looking information and management expectations to measure lifetime expected credit losses of receivables. The maximum exposure to credit risk related to non-derivative financial assets is their carrying value.

FAIR VALUE MEASUREMENTS

Our financial assets and liabilities measured at fair value on a recurring basis include derivatives and other financial instruments. We also disclose the fair value of other financial instruments not measured at fair value. The fair value of financial instruments reflects our best estimates of market value based on generally accepted valuation techniques or models and is supported by observable market prices and rates. When such values are not available, we use discounted cash flow analysis from applicable yield curves based on observable market inputs to estimate fair value.

FAIR VALUE OF FINANCIAL INSTRUMENTS

We categorize our financial instruments measured at fair value into one of three different levels depending on the observability of the inputs employed in the measurement.

Level 1
Level 1 includes financial instruments measured at fair value based on unadjusted quoted prices for identical assets and liabilities in active markets that are accessible at the measurement date. An active market for a financial instrument is considered to be a market where transactions occur with sufficient frequency and volume to provide pricing information on an ongoing basis. Under the fair value hierarchy, cash and cash equivalents are classified as Level 1. Our Level 1 instruments consist primarily of exchange-traded derivatives used to mitigate the risk of crude oil price fluctuations, US and Canadian treasury bills, and investments in exchange-traded funds held by our captive insurance subsidiary. We also hold restricted long-term investments in exchange-traded funds and common shares in trusts in accordance with the CER's regulatory requirements under the LMCI and to cover future pipeline decommissioning costs in the state of Minnesota.

Level 2
Level 2 includes financial instrument valuations determined using directly or indirectly observable inputs other than quoted prices included within Level 1. Financial instruments in this category are valued using models or other industry standard valuation techniques derived from observable market data. Such valuation techniques include inputs such as quoted forward prices, time value, volatility factors and broker quotes that can be observed or corroborated in the market for the entire duration of the financial instrument. Derivatives valued using Level 2 inputs include non-exchange traded derivatives such as over-the-counter foreign exchange forward and cross-currency swap contracts, interest rate swaps, physical forward commodity contracts, as well as commodity swaps and options for which observable inputs can be obtained.

We have also categorized the fair value of our long-term debt, investments in debt securities held by our captive insurance subsidiary, and restricted long-term investments in Canadian government bonds held in trust in accordance with the CER's regulatory requirements under the LMCI as Level 2. The fair value of our long-term debt is based on quoted market prices for instruments of similar credit risk and tenor. When possible, the fair value of our restricted long-term investments is based on quoted market prices for similar instruments and, if not available, based on broker quotes.

Level 3
Level 3 includes derivative valuations based on inputs which are less observable, unavailable or where the observable data does not support a significant portion of the derivative's fair value. Generally, Level 3 derivatives are longer dated transactions, occur in less active markets, occur at locations where pricing information is not available or have no binding broker quote to support Level 2 classification. We have developed methodologies, benchmarked against industry standards, to determine fair value for these derivatives based on the extrapolation of observable future prices and rates. Derivatives valued using Level 3 inputs primarily include long-dated derivative power, NGL and natural gas contracts, basis swaps, commodity swaps, and power and energy swaps, physical forward commodity contracts, as well as options. We do not have any other financial instruments categorized in Level 3.

We use the most observable inputs available to estimate the fair value of our derivatives. When possible, we estimate the fair value of our derivatives based on quoted market prices. If quoted market prices are not available, we use estimates from third-party brokers. For non-exchange traded derivatives classified in Levels 2 and 3, we use standard valuation techniques to calculate the estimated fair value. These methods include discounted cash flows for forwards and swaps and Black-Scholes-Merton pricing models for options. Depending on the type of derivative and nature of the underlying risk, we use observable market prices (interest, foreign exchange, commodity and share price) and volatility as primary inputs to these valuation techniques. Finally, we consider our own credit default swap spread, as well as the credit default swap spreads associated with our counterparties, in our estimation of fair value.

Fair Value of Derivatives

We have categorized our derivative assets and liabilities measured at fair value as follows:

December 31, 2025	Level 1	Level 2	Level 3	Total Gross Derivative Instruments
(millions of Canadian dollars)				
Financial assets				
Current derivative assets				
Foreign exchange contracts	**—**	**27**	**—**	**27**
Interest rate contracts	**—**	**106**	**—**	**106**
Commodity contracts	**70**	**59**	**329**	**458**
	70	**192**	**329**	**591**
Long-term derivative assets				
Foreign exchange contracts	**—**	**52**	**—**	**52**
Interest rate contracts	**—**	**117**	**—**	**117**
Commodity contracts	**—**	**7**	**117**	**124**
	—	**176**	**117**	**293**
Financial liabilities				
Current derivative liabilities				
Foreign exchange contracts	**—**	**(364)**	**—**	**(364)**
Interest rate contracts	**—**	**(48)**	**—**	**(48)**
Commodity contracts	**(55)**	**(68)**	**(177)**	**(300)**
	(55)	**(480)**	**(177)**	**(712)**
Long-term derivative liabilities				
Foreign exchange contracts	**—**	**(819)**	**—**	**(819)**
Interest rate contracts	**—**	**(84)**	**—**	**(84)**
Commodity contracts	**—**	**(11)**	**(81)**	**(92)**
	—	**(914)**	**(81)**	**(995)**
Total net financial asset/(liability)				
Foreign exchange contracts	**—**	**(1,104)**	**—**	**(1,104)**
Interest rate contracts	**—**	**91**	**—**	**91**
Commodity contracts	**15**	**(13)**	**188**	**190**
	15	**(1,026)**	**188**	**(823)**

December 31, 2024	Level 1	Level 2	Level 3	Total Gross Derivative Instruments
(millions of Canadian dollars)				
Financial assets				
Current derivative assets				
Foreign exchange contracts	—	125	—	125
Interest rate contracts	—	67	—	67
Commodity contracts	34	72	256	362
Other contracts	—	3	—	3
	34	267	256	557
Long-term derivative assets				
Foreign exchange contracts	—	83	—	83
Interest rate contracts	—	146	—	146
Commodity contracts	1	14	182	197
	1	243	182	426
Financial liabilities				
Current derivative liabilities				
Foreign exchange contracts	—	(804)	—	(804)
Interest rate contracts	—	(80)	—	(80)
Commodity contracts	(52)	(116)	(283)	(451)
	(52)	(1,000)	(283)	(1,335)
Long-term derivative liabilities				
Foreign exchange contracts	—	(1,579)	—	(1,579)
Interest rate contracts	—	(80)	—	(80)
Commodity contracts	(1)	(31)	(207)	(239)
	(1)	(1,690)	(207)	(1,898)
Total net financial asset/(liability)				
Foreign exchange contracts	—	(2,175)	—	(2,175)
Interest rate contracts	—	53	—	53
Commodity contracts	(18)	(61)	(52)	(131)
Other contracts	—	3	—	3
	(18)	(2,180)	(52)	(2,250)

The significant unobservable inputs used in the fair value measurement of Level 3 derivative instruments were as follows:

December 31, 2025	Fair Value	Unobservable Input	Minimum Price/ Volatility	Maximum Price/Volatility	Weighted Average Price/Volatility	Unit of Measurement
(fair value in millions of Canadian dollars)						
Commodity contracts - financial[1]						
Natural gas	**6**	**Forward gas price**	**3.47**	**26.99**	**4.99**	**$/mmbtu[2]**
Crude	**51**	**Forward crude price**	**59.10**	**81.17**	**72.99**	**$/barrel**
Power	**(7)**	**Forward power price**	**33.74**	**196.77**	**73.14**	**$/MW/H**
Commodity contracts - physical[1]						
Natural gas	**(4)**	**Forward gas price**	**1.13**	**21.65**	**4.32**	**$/mmbtu[2]**
Crude	**(36)**	**Forward crude price**	**58.39**	**112.73**	**78.13**	**$/barrel**
Power	**(9)**	**Forward power price**	**28.67**	**153.83**	**74.75**	**$/MW/H**
Commodity options[3]						
Natural gas	**187**	**Forward gas price**	**3.94**	**12.09**	**7.37**	**$/mmbtu[2]**
		Price volatility	**5%**	**76%**	**49%**	
	188					

1 Financial and physical forward commodity contracts are valued using a market approach valuation technique.
2 One million British thermal units (mmbtu).
3 Commodity options contracts are valued using an option model valuation technique.

If adjusted, the significant unobservable inputs disclosed in the table above would have a direct impact on the fair value of our Level 3 derivative instruments. The significant unobservable inputs used in the fair value measurement of Level 3 derivative instruments include forward commodity prices. Changes in forward commodity prices could result in significantly different fair values for our Level 3 derivatives.

Changes in the net fair value of derivative assets and liabilities classified as Level 3 in the fair value hierarchy were as follows:

Year ended December 31,	**2025**	2024
(millions of Canadian dollars)		
Level 3 net derivative liability at beginning of period	**(52)**	(131)
Total gain/(loss), unrealized		
Included in earnings[1]	**31**	(92)
Included in OCI	**—**	19
Included in regulatory assets/liabilities	**18**	130
Settlements	**191**	22
Level 3 net derivative asset/(liability) at end of period	**188**	(52)

1 Reported within Transportation and other services revenues, Commodity costs and Operating and administrative expense in the Consolidated Statements of Earnings.

There were no transfers into or out of Level 3 as at December 31, 2025 or December 31, 2024.

Net Investment Hedges

We currently have designated a portion of our US dollar-denominated debt as a hedge of our net investment in US dollar-denominated investments and subsidiaries.

During the years ended December 31, 2025 and 2024, we recognized unrealized foreign exchange gains of $500 million and losses of $1.2 billion, respectively, on the translation of US dollar-denominated debt, in OCI. During the years ended December 31, 2025 and 2024, we recognized realized losses of $81 million and $120 million, respectively, associated with the settlement of US dollar-denominated debt that had matured during the period, in OCI.

Fair Value of Other Financial Instruments

Certain long-term investments in other entities with no actively quoted prices are classified as FVMA investments and are recorded at cost less impairment. The carrying value of FVMA investments totaled $185 million and $187 million as at December 31, 2025 and December 31, 2024, respectively.

We have restricted long-term investments and cash held in trust for the purpose of funding pipeline abandonment in accordance with the CER's regulatory requirements under the LMCI, to cover future pipeline decommissioning costs in the state of Minnesota and to satisfy retirement obligations as Wexpro properties are abandoned. These investments are classified as available-for-sale, recognized at fair value and included in Restricted long-term investments and cash in the Consolidated Statements of Financial Position. As at December 31, 2025, the fair value of investments in Level 1 and Level 2 was $877 million and $416 million, respectively (December 31, 2024 - $491 million and $507 million, respectively). Our Level 2 investments had a cost basis of $426 million as at December 31, 2025 (December 31, 2024 - $540 million). There were unrealized holding gains of $99 million and $33 million on these investments for the years ended December 31, 2025 and 2024, respectively. Within Other long-term liabilities we had estimated future abandonment costs related to LMCI of $949 million and $826 million as at December 31, 2025 and 2024, respectively *(Note 7)*. During the year ended December 31, 2025, we purchased and sold investments totaling $1.3 billion and $1.1 billion, respectively (2024 - purchases of $492 million and sales of $390 million). The resulting net cash flow impact is presented under Cash Flows from Investing Activities in the Consolidated Statements of Cash Flows.

We have a wholly-owned captive insurance subsidiary whose principal activity is providing insurance and reinsurance coverage for certain insurable property and casualty risk exposures of our operating subsidiaries and certain equity investments. As at December 31, 2025, the fair value of investments in equity funds and debt securities held by our captive insurance subsidiary was nil and $1.2 billion, respectively (December 31, 2024 - $114 million and $1.1 billion, respectively). Our investments in debt securities had a cost basis of $1.2 billion as at December 31, 2025 (December 31, 2024 - $1.1 billion). These investments in equity funds and debt securities are recognized at fair value, classified as Level 1 and Level 2 in the fair value hierarchy, respectively, and are recorded in Other current assets and Long-term investments in the Consolidated Statements of Financial Position. There were unrealized holding gains of $21 million for the year ended December 31, 2025 (2024 - losses of $16 million).

As at December 31, 2025, the maturities for our investments in debt securities were as follows:

	Total	Less than 1 year	5 years	10 years	Thereafter
(millions of Canadian dollars)					
Fair value of debt securities	1,234	85	813	268	68

As at December 31, 2025 and December 31, 2024, our long-term debt, including finance lease liabilities, had a carrying value of $104.4 billion and $101.6 billion, respectively, before debt issuance costs and a fair value of $102.7 billion and $98.9 billion, respectively.

The fair value of financial assets and liabilities other than derivative instruments, certain long-term investments in other entities, restricted long-term investments, investments held by our captive insurance subsidiary and long-term debt described above approximate their carrying value due to the short period to maturity.

24. INCOME TAXES

INCOME TAX RATE RECONCILIATION

Year ended December 31,	**2025**		2024		2023	
(millions of Canadian dollars)						
Earnings before income taxes	**9,793**		7,299		7,879	
Canadian federal statutory income tax rate[1]	**15.0%**		15.0%		15.0%	
Expected federal taxes at statutory rate	**1,469**	**15.0%**	1,095	15.0%	1,182	15.0%
Increase/(decrease) resulting from:						
Provincial income taxes[2]	**245**	**2.5%**	(74)	(1.0%)	161	2.0%
Foreign tax effects:						
United States						
Statutory tax rate difference between US and Canada	**353**	**3.6%**	314	4.3%	276	3.5%
State and local income taxes, net of federal income tax effect	**61**	**0.7%**	227	3.1%	226	2.9%
Tax Credits						
Investment tax credits	**(153)**	**(1.6%)**	(11)	(0.1%)	(31)	(0.4%)
Other tax credits	**(34)**	**(0.3%)**	(12)	(0.2%)	(16)	(0.2%)
Nontaxable or nondeductible items						
Accounting impairment of goodwill[3]	**—**	**—**	208	2.9%	(88)	(1.1%)
Other adjustments						
US minimum tax	**195**	**2.0%**	163	2.2%	100	1.3%
Effects of rate-regulated accounting	**(77)**	**(0.8%)**	(110)	(1.5%)	(43)	(0.6%)
Other	**9**	**0.1%**	54	0.7%	45	0.6%
Other jurisdictions	**(74)**	**(0.8%)**	(26)	(0.4%)	(51)	(0.6%)
Nontaxable or nondeductible items						
Nontaxable portion of gain on sale of investment[4]	**—**	**—**	(147)	(2.0%)	—	—
Other adjustments						
Write-off of regulatory deferrals[5]	**32**	**0.3%**	4	0.1%	115	1.5%
Effects of rate-regulated accounting	**(87)**	**(0.9%)**	(90)	(1.2%)	(107)	(1.4%)
Part VI. Tax, net of federal Part 1 deduction[6]	**79**	**0.8%**	73	1.0%	66	0.8%
Other	**(14)**	**(0.1%)**	—	—	(14)	(0.2%)
Income tax expense and effective tax rate	**2,004**	**20.5%**	1,668	22.9%	1,821	23.1%

1 *Represents the federal statutory rate of Canada of 15%, net of the federal tax abatement and general rate reduction.*
2 *Provincial taxes in Alberta and Ontario accounted for more than 50% of the total tax effect in 2025. In both 2024 and 2023, provincial taxes in Alberta alone accounted for more than 50% of the total tax effect.*
3 *The amount in 2024 relates to the federal impact of the nondeductible goodwill impairment in the Gas Transmission segment. Refer to* Note 13 - Long-Term Investments *and* Note 15 - Goodwill.
4 *The amount in 2024 relates to the federal component of the nontaxable portion of the gain on sale relating to Alliance Pipeline and Aux Sable. Refer to* Note 13 - Long-Term Investments.
5 *The amount in 2023 relates to the federal tax impact of the derecognition of rate-regulated accounting for income tax relating to Southern Lights Canada and portions of the Canadian Mainline including Line 9 and Line 3 Replacement.*
6 *Represents the Part VI.1 tax which is levied on preferred share dividends paid in Canada.*

COMPONENTS OF PRETAX EARNINGS AND INCOME TAXES

Year ended December 31,	2025	2024	2023
(millions of Canadian dollars)			
Earnings before income taxes			
Canada	**3,391**	1,035	2,233
US	**5,920**	5,231	4,620
Other	**482**	1,033	1,026
	9,793	7,299	7,879
Income tax expense/(recovery)			
Canada			
Federal	**522**	23	395
Provincial	**245**	(74)	161
US	**1,245**	1,591	1,165
Other	**(8)**	128	100
	2,004	1,668	1,821
Current income taxes	**979**	949	401
Deferred income taxes	**1,025**	719	1,420

COMPONENTS OF DEFERRED INCOME TAXES

Deferred income tax assets and liabilities are recognized for the future tax consequences of differences between carrying amounts of assets and liabilities and their respective tax bases. Major components of deferred income tax assets and liabilities are as follows:

December 31,	2025	2024
(millions of Canadian dollars)		
Deferred income tax liabilities		
Property, plant and equipment	**(10,656)**	(11,368)
Investments	**(9,538)**	(9,043)
Regulatory assets	**(2,020)**	(1,940)
Other	**(392)**	(251)
Total deferred income tax liabilities	**(22,606)**	(22,602)
Deferred income tax assets		
Financial instruments	**363**	740
Loss carryforwards[1]	**823**	1,272
Other	**2,075**	2,088
Total deferred income tax assets	**3,261**	4,100
Less valuation allowance[2]	**(236)**	(298)
Total deferred income tax assets, net	**3,025**	3,802
Net deferred income tax liabilities	**(19,581)**	(18,800)
Presented as follows:		
Total deferred income tax assets	**701**	796
Total deferred income tax liabilities	**(20,282)**	(19,596)
Net deferred income tax liabilities	**(19,581)**	(18,800)

1 As at December 31, 2025 and 2024, represents the tax effect related to the benefit of unused tax loss carryforwards in Canada of $1.5 billion and $1.3 billion, respectively, which expire in 2031 and beyond, and in the US of $2.0 billion and $4.2 billion, respectively, with no expiration.

2 A valuation allowance has been established for certain loss and credit carryforwards, and outside basis temporary differences on investments that reduce deferred income tax assets to an amount that will more likely than not be realized.

We have not provided for deferred income taxes on the difference between the carrying value of substantially all of our foreign subsidiaries and their corresponding tax basis as the earnings of those subsidiaries are intended to be permanently reinvested in their operations. As such, these investments are not anticipated to give rise to income taxes in the foreseeable future. The difference between the carrying values of the investments and their tax bases is largely a result of unremitted earnings and currency translation adjustments. The determination of the amount of unrecognized deferred income tax liabilities applicable to such amounts is not practicable.

Enbridge and certain of our subsidiaries are subject to taxation in Canada, the US and other foreign jurisdictions. The material jurisdictions in which we are subject to potential examinations include the US (Federal) and Canada (Federal, Alberta and Québec). We are open to examination by Canadian tax authorities for the 2018 to 2025 tax years and by US tax authorities for the 2022 to 2025 tax years. We are currently under examination for income tax matters in Canada for the 2019 to 2022 tax years. We are not currently under examination for income tax matters in any other material jurisdiction where we are subject to income tax.

INCOME TAXES PAID

Year ended December 31,	**2025**	2024	2023
(millions of Canadian dollars)			
Canadian Federal	**398**	132	216
Canadian Provincial[1]	**142**	61	46
United States	**585**	592	221
Hungary	**—**	(2)	54
Switzerland	**68**	76	38
Other	**14**	2	3
Net cash paid for income taxes	**1,207**	861	578

1 Includes income taxes paid to Ontario of $46 million, $46 million, and $12 million for 2025, 2024, and 2023, respectively.

UNRECOGNIZED TAX BENEFITS

Year ended December 31,	**2025**	2024
(millions of Canadian dollars)		
Unrecognized tax benefits at beginning of year	**31**	45
Gross decreases for tax positions of prior year	**(30)**	(2)
Change in translation of foreign currency	**(1)**	4
Lapses of statute of limitations	**—**	(16)
Unrecognized tax benefits at end of year	**—**	31

We recognize accrued interest and penalties related to unrecognized tax benefits as a component of income taxes. Interest and penalties included in income taxes for the years ended December 31, 2025 and 2024 were recoveries of $6 million and $8 million, respectively. As at December 31, 2025 and 2024, interest and penalties of nil and $6 million, respectively, have been accrued.

25. PENSION AND OTHER POSTRETIREMENT BENEFITS

PENSION PLANS

We sponsor Canadian and US contributory and non-contributory registered defined benefit and defined contribution pension plans, which provide benefits covering substantially all employees. The Canadian pension plans provide defined benefit and defined contribution pension benefits to our Canadian employees. The US pension plans provide defined benefit pension benefits to our US employees. We also sponsor supplemental non-contributory defined benefit pension plans, which provide non-registered benefits for certain employees in Canada and the US.

Defined Benefit Pension Plan Benefits
Benefits payable from the defined benefit pension plans are based on each plan participant's years of service and final average remuneration. Some benefits are partially inflation-indexed after a plan participant's retirement. Our contributions are made in accordance with independent actuarial valuations. Participant contributions to contributory defined benefit pension plans are based upon each plan participant's current eligible remuneration.

Defined Contribution Pension Plan Benefits
Our contributions are based on each plan participant's current eligible remuneration. Our contributions for some defined contribution pension plans are also based on age and years of service. Our defined contribution pension benefit costs are equal to the amount of contributions required to be made by us.

Benefit Obligations, Plan Assets and Funded Status
The following table details the changes in the projected benefit obligation, the fair value of plan assets and the recorded assets or liabilities for our defined benefit pension plans:

	Canada		US	
December 31,	**2025**	2024	**2025**	2024
(millions of Canadian dollars)				
Change in projected benefit obligation				
Projected benefit obligation at beginning of year	**4,203**	4,092	**1,648**	1,036
Service cost	**97**	103	**67**	60
Interest cost	**181**	186	**80**	69
Participant contributions	**33**	32	**—**	—
Actuarial (gain)/loss[1]	**(109)**	—	**37**	(98)
Benefits paid	**(205)**	(210)	**(105)**	(100)
Transfer in	**—**	—	**6**	569
Foreign currency exchange rate changes	**—**	—	**(79)**	119
Other	**—**	—	**(8)**	(7)
Projected benefit obligation at end of year[2]	**4,200**	4,203	**1,646**	1,648
Change in plan assets				
Fair value of plan assets at beginning of year	**5,000**	4,528	**2,194**	1,052
Actual return on plan assets	**410**	627	**225**	197
Employer contributions	**12**	23	**5**	5
Participant contributions	**33**	32	**—**	—
Benefits paid	**(205)**	(210)	**(105)**	(100)
Transfer in	**—**	—	**6**	900
Foreign currency exchange rate changes	**—**	—	**(106)**	146
Other	**—**	—	**(7)**	(6)
Fair value of plan assets at end of year[3]	**5,250**	5,000	**2,212**	2,194
Overfunded status at end of year	**1,050**	797	**566**	546
Presented as follows:				
Deferred amounts and other assets	**1,176**	943	**676**	653
Other current liabilities	**(10)**	(10)	**(5)**	(6)
Other long-term liabilities	**(116)**	(136)	**(105)**	(101)
	1,050	797	**566**	546

1 Primarily due to the increase in the discount rate and changes in benefit assumptions and member data used to measure the defined benefit obligation.
2 The accumulated benefit obligation for our Canadian pension plans was $3.9 billion as at December 31, 2025 and 2024. The accumulated benefit obligation for our US pension plans was $1.6 billion as at December 31, 2025 and 2024.
3 Assets in the amount of $21 million (2024 - $18 million) and $91 million (2024- $80 million), related to our Canadian and US non-registered supplemental pension plan obligations, respectively, are held in grantor trusts and rabbi trusts that, in accordance with federal tax regulations, are not restricted from creditors. These assets are committed for the future settlement of benefit obligations included in the underfunded status as at the end of the year, however they are excluded from plan assets for accounting purposes.

Certain of our pension plans have accumulated benefit obligations in excess of the fair value of plan assets. For these plans, the accumulated benefit obligation and fair value of plan assets were as follows:

	Canada		US	
December 31,	**2025**	2024	**2025**	2024
(millions of Canadian dollars)				
Accumulated benefit obligation	**116**	404	**109**	107
Fair value of plan assets	**—**	283	**—**	—

Certain of our pension plans have projected benefit obligations in excess of the fair value of plan assets. For these plans, the projected benefit obligation and fair value of plan assets were as follows:

	Canada		US	
December 31,	**2025**	2024	**2025**	2024
(millions of Canadian dollars)				
Projected benefit obligation	**431**	428	**111**	107
Fair value of plan assets	**306**	283	**—**	—

Amount Recognized in Accumulated Other Comprehensive Income
The amount of pre-tax AOCI relating to our pension plans are as follows:

	Canada		US	
December 31,	**2025**	2024	**2025**	2024
(millions of Canadian dollars)				
Net actuarial gain	**(241)**	(122)	**(114)**	(42)
Prior service cost	**—**	—	**6**	5
Total amount recognized in AOCI[1]	**(241)**	(122)	**(108)**	(37)

1 Excludes amounts related to CTA.

Net Periodic Benefit (Credit)/Cost and Other Amounts Recognized in Comprehensive Income
The components of net periodic benefit (credit)/cost and other amounts recognized in pre-tax Comprehensive income related to our pension plans are as follows:

	Canada			US		
Year ended December 31,	**2025**	2024	2023	**2025**	2024	2023
(millions of Canadian dollars)						
Service cost[1]	**97**	103	81	**67**	60	40
Interest cost[2]	**181**	186	184	**80**	69	47
Expected return on plan assets[2]	**(345)**	(304)	(271)	**(169)**	(131)	(77)
Amortization/settlement of net actuarial (gain)/loss[2]	**—**	4	—	**(7)**	7	(4)
Amortization/curtailment of prior service credit[2]	**—**	—	—	**(1)**	(4)	—
Net periodic benefit (credit)/cost	**(67)**	(11)	(6)	**(30)**	1	6
Defined contribution benefit cost	**12**	12	12	**—**	—	—
Net pension (credit)/cost recognized in Earnings	**(55)**	1	6	**(30)**	1	6
Amount recognized in OCI:						
Reclassification of actuarial gain from regulatory assets	**—**	—	—	**(59)**	—	—
Amortization/settlement of net actuarial gain	**—**	—	—	**7**	—	4
Amortization/curtailment of prior service credit	**—**	—	—	**1**	4	—
Net actuarial (gain)/loss arising during the year	**(119)**	(173)	115	**(20)**	(116)	30
Total amount recognized in OCI	**(119)**	(173)	115	**(71)**	(112)	34
Total amount recognized in Comprehensive income	**(174)**	(172)	121	**(101)**	(111)	40

1 Reported within Operating and administrative in the Consolidated Statements of Earnings.
2 Reported within Other income/(expense) in the Consolidated Statements of Earnings.

Actuarial Assumptions

The weighted average assumptions made in the measurement of the projected benefit obligation and net periodic benefit cost of our pension plans are as follows:

	Canada			US		
	2025	2024	2023	**2025**	2024	2023
Projected benefit obligation						
Discount rate	**5.0%**	4.7%	4.6%	**5.4%**	5.5%	4.7%
Rate of salary increase	**3.0%**	3.0%	3.0%	**2.5%**	2.6%	2.6%
Cash balance interest credit rate	**N/A**	N/A	N/A	**4.7%**	4.0%	4.5%
Net periodic benefit cost						
Discount rate	**4.7%**	4.6%	5.3%	**5.5%**	4.8%	4.9%
Rate of return on plan assets	**7.0%**	6.8%	6.5%	**8.2%**	7.3%	7.4%
Rate of salary increase	**3.0%**	3.0%	2.9%	**2.6%**	2.8%	2.8%
Cash balance interest credit rate	**N/A**	N/A	N/A	**4.0%**	4.4%	4.3%

OTHER POSTRETIREMENT BENEFIT PLANS

We sponsor funded and unfunded defined benefit OPEB Plans, which provide non-contributory supplemental health, dental, life and health spending account benefit coverage for certain qualifying retired employees.

Benefit Obligations, Plan Assets and Funded Status

The following table details the changes in the accumulated postretirement benefit obligation, the fair value of plan assets and the recorded assets or liabilities for our defined benefit OPEB plans:

	Canada		US	
December 31,	**2025**	2024	**2025**	2024
(millions of Canadian dollars)				
Change in accumulated postretirement benefit obligation				
Accumulated postretirement benefit obligation at beginning of year	**210**	228	**177**	129
Service cost	**2**	3	**3**	3
Interest cost	**8**	10	**8**	7
Participant contributions	**—**	—	**5**	5
Actuarial gain[1]	**(5)**	(21)	**(3)**	(9)
Benefits paid	**(10)**	(10)	**(19)**	(20)
Transfer in	**—**	—	**—**	46
Plan amendments	**(12)**	—	**(5)**	—
Foreign currency exchange rate changes	**—**	—	**(7)**	16
Accumulated postretirement benefit obligation at end of year	**193**	210	**159**	177
Change in plan assets				
Fair value of plan assets at beginning of year	**—**	—	**278**	187
Actual return on plan assets	**—**	—	**32**	22
Employer contributions	**10**	10	**7**	7
Participant contributions	**—**	—	**5**	5
Benefits paid	**(10)**	(10)	**(19)**	(20)
Transfer in	**—**	—	**—**	55
Foreign currency exchange rate changes	**—**	—	**(14)**	20
Other	**—**	—	**—**	2
Fair value of plan assets at end of year	**—**	—	**289**	278
Overfunded/(underfunded) status at end of year	**(193)**	(210)	**130**	101
Presented as follows:				
Deferred amounts and other assets	**—**	—	**138**	113
Other current liabilities	**(12)**	(11)	**—**	—
Other long-term liabilities	**(181)**	(199)	**(8)**	(12)
	(193)	(210)	**130**	101

1 Primarily due to the increase in the discount rate and changes in benefit assumptions and member data used to measure the defined benefit obligation.

Certain of our OPEB plans have accumulated benefit obligations in excess of the fair value of plan assets. For these plans, the accumulated benefit obligation and fair value of plan assets were as follows:

	Canada		US	
December 31,	**2025**	2024	**2025**	2024
(millions of Canadian dollars)				
Accumulated benefit obligation	**193**	210	**26**	100
Fair value of plan assets	**—**	—	**19**	88

Amount Recognized in Accumulated Other Comprehensive Income
The amount of pre-tax AOCI relating to our OPEB plans are as follows:

	Canada		US	
December 31,	**2025**	2024	**2025**	2024
(millions of Canadian dollars)				
Net actuarial gain	**(98)**	(99)	**(109)**	(103)
Prior service credit	**(10)**	—	**(9)**	(16)
Total amount recognized in AOCI[1]	**(108)**	(99)	**(118)**	(119)

1 Excludes amounts related to CTA.

Net Periodic Benefit (Credit)/Cost and Other Amounts Recognized in Comprehensive Income
The components of net periodic benefit (credit)/cost and other amounts recognized in pre-tax Comprehensive income related to our OPEB plans are as follows:

	Canada			US		
Year ended December 31,	**2025**	2024	2023	**2025**	2024	2023
(millions of Canadian dollars)						
Service cost[1]	**2**	3	3	**3**	3	1
Interest cost[2]	**8**	10	11	**8**	7	6
Expected return on plan assets[2]	**—**	—	—	**(17)**	(15)	(11)
Amortization/settlement of net actuarial gain[2]	**(7)**	(5)	(6)	**(10)**	(5)	(6)
Amortization/curtailment of prior service credit[2]	**(2)**	(1)	—	**(12)**	(6)	(8)
Net periodic benefit (credit)/cost recognized in Earnings	**1**	7	8	**(28)**	(16)	(18)
Amount recognized in OCI:						
Reclassification of actuarial gain from regulatory assets	**—**	—	—	**(2)**	—	—
Amortization/settlement of net actuarial gain	**7**	5	6	**10**	5	6
Amortization/curtailment of prior service credit	**2**	1	—	**12**	6	8
Net actuarial (gain)/loss arising during the year	**(6)**	(22)	13	**(14)**	(12)	—
Prior service credit	**(12)**	—	—	**(5)**	—	—
Total amount recognized in OCI	**(9)**	(16)	19	**1**	(1)	14
Total amount recognized in Comprehensive income	**(8)**	(9)	27	**(27)**	(17)	(4)

1 Reported within Operating and administrative in the Consolidated Statements of Earnings.
2 Reported within Other income/(expense) in the Consolidated Statements of Earnings.

The weighted average assumptions made in the measurement of the accumulated postretirement benefit obligation and net periodic benefit cost of our OPEB plans are as follows:

	Canada			US		
	2025	2024	2023	**2025**	2024	2023
Accumulated postretirement benefit obligation						
Discount rate	**4.9%**	4.7%	4.6%	**5.1%**	5.3%	4.7%
Net periodic benefit cost						
Discount rate	**4.7%**	4.6%	5.3%	**5.3%**	5.5%	4.9%
Rate of return on plan assets	**N/A**	N/A	N/A	**6.6%**	6.7%	5.9%

Assumed Health Care Cost Trend Rates
The assumed rates for the next year used to measure the expected cost of benefits are as follows:

	Canada		US[1]	
	2025	2024	**2025**	2024
Health care cost trend rate assumed for next year	**4.0%**	4.0%	**4.9%**	3.2%
Rate to which the cost trend is assumed to decline (ultimate trend rate)	**4.0%**	4.0%	**4.4%**	3.7%
Year that the rate reaches the ultimate trend rate	**N/A**	N/A	**2024-2048**	2023 - 2046

1 In addition, under the Enbridge Employee Services, Inc., Health Reimbursement Account Plan, health care costs will increase by 5.0% every three years.

PLAN ASSETS
We manage the investment risk of our pension funds by setting a long-term asset mix policy for each plan after consideration of: (i) the nature of pension plan liabilities; (ii) the investment horizon of the plan; (iii) the going concern and solvency funded status and cash flow requirements of the plan; (iv) our operating environment and financial situation and our ability to withstand fluctuations in pension contributions; and (v) the future economic and capital markets outlook with respect to investment returns, volatility of returns and correlation between assets.

The overall expected rate of return on plan assets is based on the asset allocation targets with estimates for returns based on long-term expectations.

The asset allocation targets and major categories of plan assets are as follows:

	Canada			US		
	Target	December 31,		**Target**	December 31,	
Asset Category	**Allocation**	**2025**	2024	**Allocation**	**2025**	2024
Equity securities	**46.3%**	**42.4%**	39.1%	**43.3%**	**46.0%**	44.8%
Fixed income securities	**22.9%**	**29.6%**	31.6%	**23.3%**	**31.0%**	33.0%
Alternatives[1]	**30.8%**	**28.0%**	29.3%	**33.4%**	**23.0%**	22.2%

1 Alternatives include investments in private debt, private equity, infrastructure and real estate funds. Fund values are based on the net asset value of the funds that invest directly in the aforementioned underlying investments. The values of the investments have been estimated using the capital accounts representing the plan's ownership interest in the funds.

Pension Plans

The following table summarizes the fair value of plan assets for our pension plans recorded at each fair value hierarchy level:

	Canada				US			
	Level 1[1]	Level 2[2]	Level 3[3]	Total	Level 1[1]	Level 2[2]	Level 3[3]	Total
(millions of Canadian dollars)								
December 31, 2025								
Cash and cash equivalents	**203**	**—**	**—**	**203**	**35**	**—**	**—**	**35**
Equity securities[4]								
Canada	**—**	**59**	**—**	**59**	**—**	**—**	**—**	**—**
Global	**167**	**2,002**	**—**	**2,169**	**27**	**990**	**—**	**1,017**
Fixed income securities[4]								
Government	**—**	**606**	**—**	**606**	**—**	**219**	**—**	**219**
Corporate	**—**	**744**	**—**	**744**	**—**	**431**	**—**	**431**
Alternatives[5]	**—**	**—**	**1,469**	**1,469**	**—**	**—**	**510**	**510**
Total pension plan assets at fair value	**370**	**3,411**	**1,469**	**5,250**	**62**	**1,640**	**510**	**2,212**
December 31, 2024								
Cash and cash equivalents	201	—	—	201	57	—	—	57
Equity securities[4]								
Canada	—	3	—	3	—	—	—	—
Global	134	1,817	—	1,951	27	954	—	981
Fixed income securities[4]								
Government	—	543	—	543	—	194	—	194
Corporate	—	838	—	838	—	474	—	474
Alternatives[5]	—	—	1,464	1,464	—	—	488	488
Total pension plan assets at fair value	335	3,201	1,464	5,000	84	1,622	488	2,194

1 Level 1 assets include assets with quoted prices in active markets for identical assets.
2 Level 2 assets include assets with significant observable inputs.
3 Level 3 assets include assets with significant unobservable inputs.
4 Pension plan assets include $67 million (2024 - $77 million) of indirectly held related party equity and fixed income securities investments.
5 Alternatives include investments in private debt, private equity, infrastructure and real estate funds.

Changes in the net fair value of pension plan assets classified as Level 3 in the fair value hierarchy were as follows:

	Canada		US	
December 31,	**2025**	2024	**2025**	2024
(millions of Canadian dollars)				
Balance at beginning of year	**1,464**	1,290	**488**	433
Unrealized and realized gains/(losses)	**(9)**	104	**7**	63
Purchases and settlements, net	**14**	70	**15**	(8)
Balance at end of year	**1,469**	1,464	**510**	488

OPEB Plans

The following table summarizes the fair value of plan assets for our US funded OPEB plans recorded at each fair value hierarchy level:

	Level 1[1]	Level 2[2]	Level 3[3]	Total
(millions of Canadian dollars)				
December 31, 2025				
Cash and cash equivalents	**11**	**—**	**—**	**11**
Equity securities				
US	**—**	**56**	**—**	**56**
Global	**—**	**102**	**—**	**102**
Fixed income securities				
Government	**65**	**7**	**—**	**72**
Corporate	**—**	**16**	**—**	**16**
Alternatives[4]	**—**	**—**	**32**	**32**
Total OPEB plan assets at fair value	**76**	**181**	**32**	**289**
December 31, 2024				
Cash and cash equivalents	4	—	—	4
Equity securities				
US	—	52	—	52
Global	—	93	—	93
Fixed income securities				
Government	71	6	—	77
Corporate	—	19	—	19
Alternatives[4]	—	—	33	33
Total OPEB plan assets at fair value	75	170	33	278

1 Level 1 assets include assets with quoted prices in active markets for identical assets.
2 Level 2 assets include assets with significant observable inputs.
3 Level 3 assets include assets with significant unobservable inputs.
4 Alternatives include investments in private debt, private equity, infrastructure and real estate funds.

Changes in the net fair value of US funded OPEB plan assets classified as Level 3 in the fair value hierarchy were as follows:

December 31,	**2025**	2024
(millions of Canadian dollars)		
Balance at beginning of year	**33**	29
Unrealized and realized gains/(losses)	**(1)**	5
Purchases and settlements, net	**—**	(1)
Balance at end of year	**32**	33

EXPECTED BENEFIT PAYMENTS

Year ending December 31,	2026	2027	2028	2029	2030	2031-2035
(millions of Canadian dollars)						
Pension						
Canada	223	228	234	240	246	1,316
US	118	120	120	121	120	619
OPEB						
Canada	12	12	12	12	12	64
US	14	14	14	14	14	64

EXPECTED EMPLOYER CONTRIBUTIONS

In 2026, we expect to contribute approximately $15 million and $6 million to the Canadian and US pension plans, respectively, and $12 million and $6 million to the Canadian and US OPEB plans, respectively.

RETIREMENT SAVINGS PLANS

In addition to the pension and OPEB plans discussed above, we also have defined contribution employee savings plans available to US employees. Employees may receive a matching contribution where we match a certain percentage of before-tax employee contributions ranging up to 6.0% of eligible pay per pay period. For the year ended December 31, 2025, pre-tax employer matching contribution costs were $39 million ($35 million in 2024 and $33 million in 2023).

26. LEASES

LESSEE

We incur lease expenses related primarily to real estate, pipelines, storage and equipment. Our leases have remaining lease terms of one month to 40 years as at December 31, 2025.

Our lease expenses are as follows:

Year ended December 31,	**2025**	2024	2023
(millions of Canadian dollars)			
Operating lease costs[1]	**101**	132	131
Finance lease costs:			
Amortization of ROU assets[2]	**56**	20	21
Interest on lease liabilities[2]	**29**	18	14

1 Reported within Operating and administrative expense in the Consolidated Statements of Earnings.
2 Amortization of ROU assets and interest on lease liabilities are reported within Depreciation and amortization and Interest expense, respectively, in the Consolidated Statements of Earnings.

Other supplementary lease information is as follows:

Year ended December 31,	**2025**	2024	2023
(millions of Canadian dollars)			
Cash paid for amounts included in the measurement of lease liabilities			
Cash used in operating activities - operating leases	**102**	128	129
Cash used in operating activities - finance leases	**25**	13	2
Cash used in financing activities	**54**	13	17
ROU assets obtained in exchange for lease liabilities			
Operating leases	**164**	258	67
Finance leases	**148**	2	250

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December 31,	**2025**	2024
(millions of Canadian dollars, except lease term and discount rate)		
Operating leases[1]		
Operating lease right-of-use assets, net[2]	**597**	785
Operating lease liabilities - current[3]	**79**	121
Operating lease liabilities - long-term[3]	**587**	738
Total operating lease liabilities	**666**	859
Finance leases		
Finance lease right-of-use assets, net[4]	**554**	294
Finance lease liabilities - current[5]	**46**	16
Finance lease liabilities - long-term[5]	**531**	300
Total finance lease liabilities	**577**	316
Weighted average remaining lease term		
Operating leases	**14 years**	14 years
Finance leases	**28 years**	31 years
Weighted average discount rate		
Operating leases	**4.8%**	4.8%
Finance leases	**5.7%**	5.8%

1 Affiliate ROU assets, current lease liabilities and long-term lease liabilities as at December 31, 2025 were $35 million (December 31, 2024 - $42 million), $6 million (December 31, 2024 - $6 million) and $30 million (December 31, 2024 - $37 million), respectively.

2 Operating lease ROU assets are reported under Deferred amounts and other assets in the Consolidated Statements of Financial Position.

3 Current operating lease liabilities and long-term operating lease liabilities are reported under Other current liabilities and Other long-term liabilities, respectively, in the Consolidated Statements of Financial Position.

4 Finance lease ROU assets are reported under Property, plant and equipment, net in the Consolidated Statements of Financial Position.

5 Current finance lease liabilities and long-term finance lease liabilities are reported under Current portion of long-term debt and Long-term debt in the Consolidated Statements of Financial Position.

As at December 31, 2025, our operating and finance lease liabilities are expected to mature as follows:

	Operating leases	Finance leases
(millions of Canadian dollars)		
2026	**103**	**75**
2027	**96**	**62**
2028	**84**	**54**
2029	**67**	**44**
2030	**58**	**36**
Thereafter	**535**	**991**
Total undiscounted lease payments	**943**	**1,262**
Less imputed interest	**(277)**	**(685)**
Total	**666**	**577**

LESSOR

We receive revenues from operating leases primarily related to natural gas and crude oil storage and processing facilities, and wind power generation assets. Our operating lease agreements have remaining lease terms of eight months to 26 years as at December 31, 2025.

Year ended December 31,	**2025**	2024	2023
(millions of Canadian dollars)			
Operating lease income	**235**	229	241
Variable lease income	**336**	321	299
Total lease income[1]	**571**	550	540

1 Lease income is recorded within Transportation and other services revenues in the Consolidated Statements of Earnings.

As at December 31, 2025, our future lease payments to be received under operating lease and sales-type lease contracts where we are the lessor are as follows:

	Operating leases	Sales-type leases
(millions of Canadian dollars)		
2026	**211**	**117**
2027	**194**	**4**
2028	**190**	**5**
2029	**190**	**5**
2030	**175**	**5**
Thereafter	**1,221**	**187**
Future lease payments	**2,181**	**323**

27. OTHER INCOME/(EXPENSE)

Year ended December 31,	**2025**	2024	2023
(millions of Canadian dollars)			
Realized foreign currency gain/(loss)	**(428)**	121	(129)
Unrealized foreign currency gain/(loss)	**1,136**	(2,199)	821
Net defined pension and OPEB credit	**293**	188	135
Other	**633**	564	397
	1,634	(1,326)	1,224

28. CHANGES IN OPERATING ASSETS AND LIABILITIES

Year ended December 31,	**2025**	2024	2023
(millions of Canadian dollars)			
Trade receivables and unbilled revenues	**(516)**	(1,638)	1,125
Accounts receivable from affiliates	**(3)**	(23)	18
Inventory	**(166)**	177	763
Other current and non-current assets	**(89)**	(426)	1,301
Trade payables and accrued liabilities	**361**	1,383	(1,542)
Accounts payable to affiliates	**22**	(8)	(66)
Interest payable	**(54)**	157	199
Other current and non-current liabilities	**(960)**	245	513
	(1,405)	(133)	2,311

29. RELATED PARTY TRANSACTIONS

Related party transactions are conducted in the normal course of business and, unless otherwise noted, are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties.

We provide transportation services to several significantly influenced investees which we record as transportation and other services revenue. We also purchase natural gas and crude oil with several of our significantly influenced investees which we record as commodity costs. We contract for firm transportation services to meet our annual natural gas supply requirements which we record as gas distribution costs.

Our transactions with significantly influenced investees are as follows:

Year ended December 31,	**2025**	2024	2023
(millions of Canadian dollars)			
Transportation and other revenues	**197**	181	169
Operating and administrative[1]	**615**	637	625
Commodity costs	**38**	22	63
Gas distribution costs	**149**	147	140

1 During the years ended December 31, 2025, 2024 and 2023, we had Operating and administrative costs from the Seaway Crude Pipeline System of $621 million, $650 million and $632 million, respectively. These costs are a result of an operational contract where we utilize capacity on Seaway Crude Pipeline System assets for use in our Liquids Pipelines business.

For details on guarantee arrangements entered with related parties, refer to *Note 12 - Variable Interest Entities* and *Note 31 - Guarantees.*

AFFILIATE LOAN

The following loan from affiliate is evidenced by formal loan agreements:

December 31,	**2025**	2024
(millions of Canadian dollars)		
EIH S.à r.l.[1]	**228**	172

1 The loan is denominated in Euros. As at December 31, 2025, the outstanding balance of the demand loan is €141 million (2024 - €116 million). During the year ended December 31, 2025, we borrowed on the demand loan of €25 million. The demand loan bears an interest rate of 3.10%. The amounts are included in Other current liabilities in the Consolidated Statements of Financial Position.

30. COMMITMENTS AND CONTINGENCIES

COMMITMENTS

As at December 31, 2025, we have commitments as detailed below:

	Total	Less than 1 year	2 years	3 years	4 years	5 years	Thereafter
(millions of Canadian dollars)							
Purchase of services, pipe and other materials, including transportation[1]	16,968	6,939	2,524	2,163	1,525	875	2,942
Maintenance agreements[2]	414	53	54	35	36	35	201
Right-of-way commitments[3]	902	44	45	49	45	45	674
Total	18,284	7,036	2,623	2,247	1,606	955	3,817

1 Includes capital and operating commitments. Consists primarily of firm capacity payments that provide us with uninterrupted firm access to natural gas and crude oil transportation and storage contracts; contractual obligations to purchase physical quantities of natural gas; and power commitments.
2 Consists primarily of maintenance service contracts for our wind and solar assets.
3 Our right-of-way obligations primarily consist of non-lease agreements that existed at the time of adopting Topic 842 Leases, at which time we elected a practical expedient that allowed us to continue our historical treatment.

ENVIRONMENTAL
We are subject to various Canadian and US federal, provincial/state and local laws relating to the protection of the environment. These laws and regulations can change from time to time, imposing new obligations on us.

Environmental risk is inherent to liquid hydrocarbon and natural gas pipeline operations, and Enbridge and its affiliates are, at times, subject to environmental remediation obligations at various sites where we operate. We manage this environmental risk through appropriate environmental policies, programs and practices to minimize any impact our operations may have on the environment. To the extent that we are unable to recover payment for environmental liabilities from insurance or other potentially responsible parties, we will be responsible for payment of costs arising from environmental incidents associated with our operating activities.

OTHER LITIGATION
We and our subsidiaries are subject to various other legal and regulatory actions and proceedings which arise in the normal course of business, including interventions in regulatory proceedings and challenges to regulatory approvals and permits. While the final outcome of such actions and proceedings cannot be predicted with certainty, management believes that the resolution of such actions and proceedings will not have a material impact on our consolidated financial position or results of operations.

INSURANCE
We maintain an insurance program for us, our subsidiaries and certain of our affiliates to mitigate a certain portion of our risks. However, not all risks are insurable, or are insured by us. We self-insure a significant portion of certain risks through our wholly-owned captive insurance subsidiary, which requires certain assumptions and management judgment regarding the frequency and severity of claims, claim development and settlement practices and the selection of estimated loss among estimates derived using different methods. Our insurance coverage is also subject to terms and conditions, exclusions and large deductibles or self-insured retentions which may reduce or eliminate coverage in certain circumstances.

Our insurance policies are generally renewed annually and premiums, terms, policy limits and/or deductibles can vary substantially based on factors like market conditions. We can give no assurance that we will be able to maintain adequate insurance in the future at rates or on other terms we consider commercially reasonable. In such case, we may decide to self-insure additional risks.

In the unlikely event multiple insurable incidents occur which exceed coverage limits within the same insurance period, the total insurance coverage will be allocated among entities on an equitable basis based on an insurance allocation agreement we have entered into with us and other subsidiaries.

31. GUARANTEES

In the normal course of conducting business, we may enter into agreements which indemnify third parties and affiliates. We may also be a party to agreements with subsidiaries, jointly owned entities, unconsolidated entities such as equity method investees, or entities with other ownership arrangements that require us to provide financial and performance guarantees. Financial guarantees include stand-by letters of credit, debt guarantees, surety bonds and indemnifications. To varying degrees, these guarantees involve elements of performance and credit risk, which are not included in our Consolidated Statements of Financial Position. Performance guarantees require us to make payments to a third party if the guaranteed entity does not perform on its contractual obligations, such as debt agreements, purchase or sale agreements, and construction contracts and leases.

We typically enter into these arrangements to facilitate commercial transactions with third parties. Examples include indemnifying counterparties pursuant to sale agreements for assets or businesses in matters such as breaches of representations, warranties or covenants, loss or damages to property, environmental liabilities, and litigation and contingent liabilities. We may indemnify third parties for certain liabilities relating to environmental matters arising from operations prior to the purchase or transfer of certain assets and interests. Similarly, we may indemnify the purchaser of assets for certain tax liabilities incurred while we owned the assets, a misrepresentation related to taxes that result in a loss to the purchaser or other certain tax liabilities related to those assets.

The likelihood of having to perform under these guarantees and indemnifications is largely dependent upon future operations of various subsidiaries, investees and other third parties, or the occurrence of certain future events. We cannot reasonably estimate the total maximum potential amounts that could become payable to third parties and affiliates under such agreements described above; however, historically, we have not made any significant payments under guarantee or indemnification provisions. While these agreements may specify a maximum potential exposure, or a specified duration to the guarantee or indemnification obligation, there are circumstances where the amount and duration are unlimited. As at December 31, 2025, guarantees and indemnifications have not had, and are not reasonably likely to have, a material effect on our financial condition, changes in financial condition, earnings, liquidity, capital expenditures or capital resources.

For details on guarantee arrangements entered with related parties, refer to note *Note 12 - Variable Interest Entities* and *Note 29 - Related Party Transactions*.

32. QUARTERLY FINANCIAL DATA (UNAUDITED)

	Q1	Q2	Q3	Q4	Total
(unaudited; millions of Canadian dollars, except per share amounts)					
2025					
Operating revenues	**18,502**	**14,876**	**14,639**	**17,177**	**65,194**
Operating income	**3,672**	**2,289**	**2,271**	**2,726**	**10,958**
Earnings	**2,490**	**2,321**	**847**	**2,131**	**7,789**
Earnings attributable to controlling interests	**2,364**	**2,279**	**788**	**2,060**	**7,491**
Earnings attributable to common shareholders	**2,261**	**2,177**	**682**	**1,952**	**7,072**
Earnings per common share					
Basic	**1.04**	**1.00**	**0.30**	**0.89**	**3.23**
Diluted	**1.03**	**1.00**	**0.30**	**0.89**	**3.22**
2024					
Operating revenues	11,038	11,336	14,882	16,217	53,473
Operating income	2,711	2,273	2,218	2,447	9,649
Earnings	1,565	2,001	1,447	618	5,631
Earnings attributable to controlling interests	1,512	1,943	1,391	595	5,441
Earnings attributable to common shareholders	1,419	1,848	1,293	493	5,053
Earnings per common share					
Basic	0.67	0.86	0.59	0.23	2.34
Diluted	0.67	0.86	0.59	0.23	2.34