ENBRIDGE INC.

MANAGEMENT'S DISCUSSION AND ANALYSIS

December 31, 2025

INTRODUCTION

The following discussion and analysis of our financial condition and results of operations is based on and should be read in conjunction with "Forward-Looking Information" and "Non-GAAP and Other Financial Measures", Part I. *Item 1A. Risk Factors* and our consolidated financial statements and the accompanying notes included in Part II. *Item 8. Financial Statements and Supplementary Data* of this Annual Report on Form 10-K.

This section of our Annual Report on Form 10-K discusses 2025 and 2024 items and year-over-year comparisons between 2025 and 2024. For discussion of 2023 items and year-over-year comparisons between 2024 and 2023, refer to Part II. *Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations* of our Annual Report on Form 10-K for the year ended December 31, 2024.

RECENT DEVELOPMENTS

LIQUIDS PIPELINES INVESTMENT

Mainline System Capital Investment

In 2025, we announced plans to invest up to US$1.3 billion in our Mainline System through 2028. These investments are expected to earn a return through the Mainline Tolling Settlement and will be focused on extending the service life of the underlying assets, as well as further enhancing reliability and efficiency given continuing demands on the system.

NONCONTROLLING INTEREST INVESTMENT

BC Pipeline System

On July 2, 2025, Stonlasec8 Indigenous Investments Limited Partnership (the First Nations Partnership), an entity representing 38 First Nations in British Columbia (BC), invested approximately $736 million in our Westcoast Energy Inc. BC natural gas pipeline system.

As at December 31, 2025, we own 87.53% of the BC Pipeline system, which is included in our Gas Transmission segment, and continue to manage and operate the pipeline system. The First Nations Partnership owns the remaining 12.47% interest.

GAS TRANSMISSION RATE PROCEEDINGS

Algonquin

Algonquin Gas Transmission, LLC (Algonquin) filed a rate case on May 30, 2024 and a settlement in principle was reached with customers in December 2024. A Stipulation and Agreement was approved by the Federal Energy Regulatory Commission (FERC) on April 25, 2025 with rates effective December 1, 2024.

Maritimes & Northeast

Maritimes & Northeast (M&N) United States (US) filed a rate case on May 30, 2024 and a settlement in principle was reached with customers in December 2024. A Stipulation and Agreement was approved by the FERC on April 25, 2025 with rates effective January 1, 2025.

The toll settlement agreement for M&N Canada expired in December 2025. M&N Canada reached a 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 Canada Energy Regulator (CER) for review and approval. A CER decision is expected in the first quarter of 2026.

East Tennessee
East Tennessee Natural Gas, LLC (East Tennessee) filed a rate case on April 29, 2025. On May 29, 2025, the FERC issued an order accepting and suspending tariff records, subject to refund, conditions, and establishing hearing procedures. In compliance with the order, East Tennessee made a filing to implement the rates to be effective November 1, 2025, subject to refund. Settlement discussions with shippers commenced in the third quarter of 2025.

Vector
Vector Pipeline L.P. (Vector) filed a rate case on May 30, 2025. On June 30, 2025, the FERC issued an order accepting and suspending tariff records filed in this rate case, and establishing hearing procedures. In compliance with the order, Vector placed the proposed rates into effect on July 1, 2025. Additionally, on July 1, 2025, the chief administrative law judge issued an order consolidating Vector’s outstanding review of rates initiated by the FERC in 2024 with Vector’s May 30, 2025 rate case filing. In February 2026, Vector reached a settlement in principle with all active participants that resolves all issues in the consolidated rate case, which will be filed for FERC approval in the first half of 2026. If approved, settlement rates will be effective April 1, 2026.

GAS DISTRIBUTION AND STORAGE RATE APPLICATIONS
Enbridge Gas Ontario
In October 2022, Enbridge Gas Inc. (Enbridge Gas Ontario) filed its application with the Ontario Energy Board (OEB) to establish a 2024–2028 Incentive Regulation (IR) rate setting framework:

- Phase 1 of the application established 2024 base rates on a cost-of-service basis.
- Phase 2 established a price cap incentive rate-setting (Price Cap IR) mechanism for 2025–2028.
- Phase 3 addresses cost allocation and the harmonization of rates, rate classes and services. Completion of Phase 3 is expected in 2026.

Phase 1
In December 2023, the OEB issued its decision on Phase 1. Enbridge Gas Ontario continues to appeal through Ontario courts the OEB's Phase 1 findings on depreciation, equity thickness and undepreciated capital, with hearing dates scheduled in 2026.

Phase 2
Through a November 2024 decision on the Phase 2 partial settlement proposal, and a May 2025 decision on outstanding issues, the OEB approved a Price Cap IR mechanism for 2025–2028 rates. The mechanism includes an earnings sharing mechanism which requires earnings in excess of 100 basis points over the allowed return on equity (ROE) to be shared equally with customers, and 90% of any earnings in excess of 300 basis points over the allowed ROE. Rates effective January 1, 2025 and January 1, 2026, were set using the approved Price Cap IR mechanism.

Generic Cost of Capital Proceeding
In March 2025, the OEB released its decision in the generic cost of capital proceeding. The OEB determined that Enbridge Gas Ontario's equity thickness would remain at 38% as approved in the Phase 1 decision. The OEB also revised the formula for calculating ROE by reducing flotation costs by 25 basis points. The new formula will be applicable to Enbridge Gas Ontario at its next rebasing expected in 2029. Until then, rates will continue to reflect the 2024 ROE of 9.21%.

Enbridge Gas Ohio
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) which were recognized for the year ended December 31, 2025.

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.

Enbridge Gas North Carolina
In April 2025, Enbridge Gas North Carolina filed its first rates application since 2021 with the North Carolina Utilities 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 Utilities 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.

Enbridge Gas Utah
In May 2025, Enbridge Gas Utah filed its first rates application since 2022 with the Utah Public Service 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.

FINANCING UPDATE

We completed long-term debt issuances totaling $4.6 billion and US$4.7 billion during the year ended December 31, 2025.

On February 25, 2025, Enbridge Pipelines Inc. redeemed below par all of the outstanding $100 million 4.10% medium-term notes that carried an original maturity date in July 2112.

On July 28, 2025, Enbridge Energy Partners, L.P. (EEP) redeemed at par all of the outstanding US$500 million 5.88% senior notes that carried an original maturity date in October 2025.

During our annual renewal process, we renewed and extended approximately $22.1 billion of our credit facilities with maturities ranging from 2027–2030.

Our 2025 financing activities have provided significant liquidity that we expect will enable us to fund our current portfolio of capital projects and acquisitions without requiring access to the capital markets for the next 12 months, should market access be restricted or pricing be unattractive. Refer to *Liquidity and Capital Resources*.

As at December 31, 2025, after adjusting for the impact of floating-to-fixed interest rate swap hedges, approximately 9% of our total debt is exposed to floating rates. Refer to Part II. *Item 8. Financial Statements and Supplementary Data - Note 23 - Risk Management and Financial Instruments* for more information on our interest rate hedging program.

FORWARD-LOOKING INFORMATION

Forward-looking information, or forward-looking statements, have been included in this management's discussion and analysis (MD&A) to provide information about us and our subsidiaries and affiliates, including management's assessment of our and our subsidiaries' future plans and operations. This information may not be appropriate for other purposes. Forward-looking statements are typically identified by words such as ''anticipate", "believe", "estimate", "expect", "forecast", "intend", "likely", "plan", "project", "target" and similar words suggesting future outcomes or statements regarding an outlook. Forward-looking information or statements included or incorporated by reference in this document include, but are not limited to, statements with respect to the following: our corporate vision and strategy, including strategic priorities and enablers; expected supply of, demand for, exports of and prices of crude oil, natural gas, natural gas liquids (NGL), liquefied natural gas (LNG), renewable natural gas (RNG) and renewable energy; energy transition and lower-carbon energy, and our approach thereto; environmental, social and governance (ESG) and sustainability goals, practices and performance; industry and market conditions; anticipated utilization of our assets; dividend growth and payout policy; financial strength and flexibility; expectations on sources of liquidity and sufficiency of financial resources; expected strategic priorities and performance of the Liquids Pipelines, Gas Transmission, Gas Distribution and Storage, and Renewable Power Generation businesses; the characteristics, anticipated benefits, financing and timing of our acquisitions, dispositions and other transactions, including the anticipated benefits of the acquisitions of three US gas utilities (US Gas Utilities) from Dominion Energy, Inc. (the Acquisitions); expected future actions of regulators and courts; government trade policies and potential impacts of potential and announced tariffs, duties, fees, economic sanctions, or other trade measures and the timing thereof; expected costs, benefits and in-service dates related to announced projects and projects under construction; expected capital expenditures; investable capacity and capital allocation priorities; expected equity funding requirements for our commercially secured growth program; expected future growth, development and expansion opportunities; expected optimization and efficiency opportunities; expectations about our joint venture partners' ability to complete and finance projects under construction; our ability to successfully integrate the US Gas Utilities; expected closing of acquisitions, dispositions and other transactions and the timing thereof; toll and rate cases discussions and proceedings and anticipated timeline and impact therefrom, including those relating to the Gas Distribution and Storage and Gas Transmission businesses; operational, industry, regulatory, climate change and other risks associated with our businesses; and our assessment of the potential impact of the various risk factors identified herein.

Although we believe these forward-looking statements are reasonable based on the information available on the date such statements are made and processes used to prepare the information, such statements are not guarantees of future performance and readers are cautioned against placing undue reliance on forward-looking statements. By their nature, these statements involve a variety of assumptions, known and unknown risks and uncertainties and other factors, which may cause actual results, levels of activity and achievements to differ materially from those expressed or implied by such statements. Material assumptions include the following: the expected supply of, demand for, export of and prices of crude oil, natural gas, NGL, LNG, RNG and renewable energy; anticipated utilization of assets; exchange rates; inflation; interest rates; tariffs and trade policies; availability and price of labor and construction materials; the stability of our supply chain; operational reliability; maintenance of support and regulatory approvals for our projects and transactions; anticipated in-service dates; weather; the timing, terms and closing of acquisitions, dispositions and other transactions; the realization of anticipated benefits of transactions, including the Acquisitions; governmental legislation; litigation; estimated future dividends and impact of our dividend policy on our future cash flows; our credit ratings; capital project funding; hedging program; expected earnings before interest, income taxes, and depreciation and amortization (EBITDA); expected earnings/(loss); expected future cash flows; and expected distributable cash flow. Assumptions regarding the expected supply of and demand for crude oil, natural gas, NGL, LNG, RNG and renewable energy, and the prices of these commodities, are material to and underlie all forward-looking statements, as they may impact current and future levels of demand for our services. Similarly, exchange rates, inflation, interest rates and tariffs impact the economies and business environments in which we operate and may impact levels of demand for our services and cost of inputs, and are therefore inherent in all forward-looking statements. The most relevant assumptions associated with forward-looking statements regarding announced projects and projects under construction, including estimated completion dates and expected capital expenditures, include the following: the availability and price of labor and construction materials; the stability of our supply chain; the effects of inflation and foreign exchange rates on labor and material costs; the effects of interest rates on borrowing costs; the impact of weather; and customer, government, court and regulatory approvals on construction and in-service schedules and cost recovery regimes.

Our forward-looking statements are subject to risks and uncertainties pertaining to the successful execution of our strategic priorities; operating performance; legislative and regulatory parameters; litigation; acquisitions, dispositions and other transactions and the realization of anticipated benefits therefrom (including the anticipated benefits from the Acquisitions); evolving government trade policies, including potential and announced tariffs, duties, fees, economic sanctions or other trade measures; operational dependence on third parties; dividend policy; project approval and support; renewals of rights-of-way; weather; economic and competitive conditions; public opinion; changes in tax laws and tax rates; exchange rates; inflation; interest rates; commodity prices; access to and cost of capital; our ability to maintain adequate insurance in the future at commercially reasonable rates and terms; political decisions; global geopolitical conflicts and conditions; and the supply of, demand for and prices of commodities and other alternative energy, including but not limited to, those risks and uncertainties discussed in this MD&A and in our other filings with Canadian and US securities regulators. The impact of any one assumption, risk, uncertainty or factor on a particular forward-looking statement is not determinable with certainty as these are interdependent and our future course of action depends on management's assessment of all information available at the relevant time. Except to the extent required by applicable law, we assume no obligation to publicly update or revise any forward-looking statements made in this MD&A or otherwise, whether as a result of new information, future events or otherwise. All forward-looking statements, whether written or oral, attributable to us or persons acting on our behalf, are expressly qualified in their entirety by these cautionary statements.

NON-GAAP AND OTHER FINANCIAL MEASURES

This Management's Discussion and Analysis of Financial Condition and Results of Operations (MD&A) makes reference to non-GAAP and other financial measures, including EBITDA. EBITDA is defined as earnings before interest, income taxes and depreciation and amortization. Management uses EBITDA to assess the performance of Enbridge and to set targets. Management believes the presentation of EBITDA gives useful information to investors as it provides increased transparency and insight into the performance of Enbridge.

The non-GAAP and other financial measures are not measures that have a standardized meaning prescribed by the accounting principles generally accepted in the US (US GAAP) and are not US GAAP measures. Therefore, these measures may not be comparable with similar measures presented by other issuers. A reconciliation of historical non-GAAP and other financial measures to the most directly comparable GAAP measures is set out in this MD&A and is available on our website. Additional information on non-GAAP and other financial measures may be found on our website, www.sedarplus.ca or www.sec.gov.

RESULTS OF OPERATIONS

Year ended December 31,	2025	2024	2023
(millions of Canadian dollars, except per share amounts)			
Segment earnings/(loss) before interest, income taxes and depreciation and amortization[1]			
Liquids Pipelines	**9,396**	9,531	9,383
Gas Transmission	**5,491**	5,656	4,264
Gas Distribution and Storage	**3,809**	2,869	1,592
Renewable Power Generation	**620**	733	149
Eliminations and Other	**1,161**	(1,904)	916
Earnings before interest, income taxes and depreciation and amortization[1]	**20,477**	16,885	16,304
Depreciation and amortization	**(5,661)**	(5,167)	(4,613)
Interest expense	**(5,023)**	(4,419)	(3,812)
Income tax expense	**(2,004)**	(1,668)	(1,821)
(Earnings)/loss attributable to noncontrolling interests and redeemable noncontrolling interest	**(298)**	(190)	133
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	**3.23**	2.34	2.84
Diluted earnings per common share attributable to common shareholders	**3.22**	2.34	2.84

1 *Non-GAAP financial measure. Refer to* Non-GAAP and Other Financial Measures.

EARNINGS ATTRIBUTABLE TO COMMON SHAREHOLDERS

Year ended December 31, 2025, compared with year ended December 31, 2024
Earnings attributable to common shareholders was positively impacted by $1.5 billion due to certain infrequent or other non-operating factors, primarily explained by the following:

- a non-cash, net unrealized derivative fair value gain of $1.3 billion ($999 million after-tax) in 2025, compared with a net unrealized loss of $2.1 billion ($1.6 billion after-tax) in 2024, reflecting changes in the mark-to-market value of derivative financial instruments used to manage foreign exchange, interest rate and commodity price risks; and
- equity earnings of $87 million ($65 million after-tax) from our investment in DCP Midstream, LP (DCP), as a result of DCP's gain on disposition from certain pipeline assets; partially offset by
- the absence in 2025 of a gain on sale of $1.1 billion ($765 million after-tax) on the disposition of our interests in the Alliance Pipeline and Aux Sable Liquid Products LP, Aux Sable Midstream LLC, and Aux Sable Canada LP (Aux Sable);
- an impairment of $330 million ($261 million after-tax) of certain rate-regulated assets related to pension and other disallowances as a result of the Ohio Commission's June 2025 order related to Enbridge Gas Ohio's rate case; and
- an impairment loss of $240 million ($176 million after-tax) of certain non-core Liquids Pipelines assets.

The non-cash, unrealized derivative fair value gains and losses discussed above generally arise as a result of our comprehensive economic hedging program to mitigate foreign exchange, interest rate and commodity price risks. This program creates volatility in reported short-term earnings through the recognition of unrealized non-cash gains and losses on derivative instruments used to hedge these risks. Over the long-term, we believe our hedging program supports the reliable cash flows and dividend growth upon which our investor value proposition is based.

After taking into consideration the factors above, the remaining $541 million increase in earnings attributable to common shareholders is primarily explained by the following significant business factors:

- full year of contributions from the US Gas Utilities in our Gas Distribution and Storage segment;
- positive earnings impact in Enbridge Gas Ontario due to colder weather in 2025 compared to a negative impact in 2024, higher storage optimization and pricing, and higher distribution margin and customer growth in our Gas Distribution and Storage segment;
- higher contributions from our Gas Transmission segment primarily due to the recognition of increased revenue attributable to Algonquin and Texas Eastern rate case settlements, favorable contracting on our US Gas Transmission assets, and contributions from the Texas Eastern Venice Extension project;
- higher contributions from Mainline System (net of sharing) due to higher demand, higher tolls, and lower power costs; and
- lower income tax expense, excluding tax on infrequent or non-operating factors discussed above, mainly driven by lower effective US tax rate primarily from the impact of higher investment tax credits.

The factors above were partially offset by:

- higher interest expense primarily due to higher average debt principal outstanding;
- higher depreciation and amortization expense mainly driven by full year ownership of the US Gas Utilities;
- lower contributions from the Gulf Coast and Mid-Continent System in our Liquids Pipelines segment primarily due to lower spot volumes on the Flanagan South Pipeline;
- lower contributions from our Gas Transmission segment due to the sale of our interests in Alliance Pipeline and Aux Sable in April 2024 and lower earnings from our Tomorrow RNG renewable natural gas facilities due to lower Renewable Identification Number (RIN) pricing and production volumes;
- the decrease in 2025 of equity earnings from Fox Squirrel Solar investment tax credits in our Renewable Power Generation segment; and
- the absence in 2025 of interest income from cash pre-funding related to Enbridge's acquisitions of the East Ohio Gas Company (EOG), Questar Gas Company (Questar) and its related Wexpro companies (Wexpro), and Public Service Company of North Carolina, Incorporated (PSNC) (together, the Acquisitions) in Eliminations and Other.

REVENUES

We generate revenues from three primary sources: transportation and other services, gas distribution sales and commodity sales.

Transportation and other services revenues of $20.2 billion, $19.7 billion and $19.2 billion, for the years ended December 31, 2025, 2024 and 2023, respectively, were earned from our crude oil and natural gas pipeline transportation businesses and also include power generation revenues from our portfolio of renewable and power generation assets. For our transportation assets operating under market-based arrangements, revenues are driven by volumes transported and the corresponding tolls for transportation services. For assets operating under take-or-pay contracts, revenues reflect the terms of the underlying contract for services or capacity. For rate-regulated assets, revenues are charged in accordance with tolls established by the regulator and, in most cost-of-service based arrangements, are reflective of our cost to provide the service plus a regulator-approved rate of return.

Gas distribution sales revenues of $9.8 billion, $6.8 billion and $5.4 billion for the years ended December 31, 2025, 2024 and 2023, respectively, were recognized in a manner consistent with the underlying rate-setting mechanism mandated by the regulator. Revenues generated by the gas distribution businesses are primarily driven by volumes delivered, which vary with weather and customer composition and utilization, as well as regulator-approved rates. The cost of natural gas is passed through rates to customers and does not ultimately impact earnings due to its flow-through nature.

Commodity sales revenues of $35.2 billion, $27.0 billion and $19.0 billion for the years ended December 31, 2025, 2024 and 2023, respectively, were generated primarily through our crude oil marketing, natural gas and power marketing businesses. This includes the purchase and sale of crude oil, natural gas, power and NGL to generate a margin, which is typically a small fraction of gross revenue. Sales revenue generated from these operations reflect activity levels which are driven by differences in commodity prices between locations, grades and points in time, rather than on absolute prices. Commodity sales revenues also include revenue generated from our Tomorrow RNG business. Any residual commodity margin risk is closely monitored and managed. Revenues from these operations depend on activity levels, which vary from year-to-year depending on market conditions and commodity prices.

Our revenues also include changes in unrealized derivative fair value gains and losses related to foreign exchange and commodity price contracts used to manage exposures from movements in foreign exchange rates and commodity prices. The mark-to-market accounting creates volatility and impacts the comparability of revenues in the short-term, but we believe over the long-term, the economic hedging program supports reliable cash flows.

BUSINESS SEGMENTS

LIQUIDS PIPELINES

Year ended December 31,	**2025**	2024	2023
(millions of Canadian dollars)			
Earnings before interest, income taxes and depreciation and amortization	**9,396**	9,531	9,383

Year ended December 31, 2025 compared with year ended December 31, 2024
EBITDA was negatively impacted by $191 million primarily due to impairment losses of $240 million related to certain non-core assets.

After taking into consideration the above, the remaining $56 million increase is primarily explained by the following significant business factors:

- higher Mainline System contributions (net of sharing) as a result of higher demand, annual escalators and surcharge effective July 1, 2024, and lower power costs from operational efficiencies and lower mill rates;
- higher contributions from Line 9 due to higher volumes; and
- the favorable effect of translating US dollar earnings at a higher average exchange rate in 2025, compared to 2024; partially offset by
- lower contributions from the Gulf Coast and Mid-Continent System primarily due to lower spot volumes on the Flanagan South Pipeline.

GAS TRANSMISSION

Year ended December 31,	**2025**	2024	2023
(millions of Canadian dollars)			
Earnings before interest, income taxes and depreciation and amortization	**5,491**	5,656	4,264

Year ended December 31, 2025 compared with year ended December 31, 2024
EBITDA was negatively impacted by $780 million due to certain infrequent or other non-operating factors primarily explained by the following:

- the absence in 2025 of a gain on sale of $1.1 billion on the disposition of interests in the Alliance Pipeline and Aux Sable; partially offset by
- the absence in 2025 of an asset impairment loss of $137 million related to the Big Sandy Pipeline;
- equity earnings of $87 million from our investment in DCP, as a result of DCP's gain on disposition from certain pipeline assets; and
- a net positive adjustment of $32 million to the gas inventory at Aitken Creek in 2025, compared to a net negative adjustment of $33 million in 2024.

After taking into consideration the factors above, the remaining $615 million increase is primarily explained by the following significant business factors:

- the recognition of increased revenue attributable to the Algonquin and Texas Eastern rate case settlements;
- contributions from the Texas Eastern Venice Extension project since service commencement in late 2024;
- higher revenues at Aitken Creek due to favorable storage spreads;
- favorable contracting on our US Gas Transmission assets;
- higher earnings from our investment in DCP;
- contributions from the acquisition of equity interests in the Whistler Parent JV, Delaware Basin Residue, LLC (DBR), and Matterhorn Express, LLC in the second and fourth quarters of 2024, and the second quarter of 2025, respectively; and
- the favorable effect of translating US dollar earnings at a higher average exchange rate in 2025, compared to 2024; partially offset by
- the absence of contributions from Alliance Pipeline and Aux Sable due to the sale of our interests in these investments in April 2024; and
- lower earnings at Tomorrow RNG primarily due to lower RIN pricing and production volumes.

GAS DISTRIBUTION AND STORAGE

Year ended December 31,	**2025**	2024	2023
(millions of Canadian dollars)			
Earnings before interest, income taxes and depreciation and amortization	**3,809**	2,869	1,592

Year ended December 31, 2025 compared with year ended December 31, 2024
EBITDA was negatively impacted by $330 million due to an impairment of certain rate-regulated assets related to pension and other disallowances as a result of the Ohio Commission's June 2025 order related to Enbridge Gas Ohio's rate case.

After taking into consideration the above, the remaining $1.3 billion increase is primarily explained by the following significant business factors:

- full year of contributions from the US Gas Utilities;
- when compared with the normal forecast embedded in rates, the positive impact of weather on EBITDA for Enbridge Gas Ontario was approximately $30 million (net of sharing) in 2025 compared to a negative impact of approximately $129 million in 2024;
- higher distribution margin resulting from increases in rates and customer base at Enbridge Gas Ontario;
- higher storage optimization and pricing at Enbridge Gas Ontario; and
- higher distribution margin resulting from increased revenue requirement from recovery of capital investments at Enbridge Gas Ohio and higher base rates at Enbridge Gas North Carolina.

RENEWABLE POWER GENERATION

Year ended December 31,	**2025**	2024	2023
(millions of Canadian dollars)			
Earnings before interest, income taxes and depreciation and amortization	**620**	733	149

Year ended December 31, 2025 compared with year ended December 31, 2024
EBITDA was positively impacted by $35 million due to certain infrequent or non-operating factors, primarily explained by:

- the absence in 2025 of an impairment loss of $55 million related to certain assets; partially offset by
- a realized loss of $139 million, partially offset by a non-cash, net unrealized gain of $112 million in 2025, compared with a net unrealized loss of $13 million in 2024, reflecting changes in the mark-to-market value of derivative financial instruments used to manage foreign exchange and commodity price risks.

After taking into consideration the factors above, the remaining $148 million decrease is primarily explained by the decrease in 2025 of equity earnings related to Fox Squirrel Solar investment tax credits.

ELIMINATIONS AND OTHER

Year ended December 31,	**2025**	2024	2023
(millions of Canadian dollars)			
Earnings/(loss) before interest, income taxes and depreciation and amortization	**1,161**	(1,904)	916

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. Eliminations and Other also includes our natural gas and power marketing businesses and the impact of new business development activities and corporate investments.

Year ended December 31, 2025 compared with year ended December 31, 2024
EBITDA was positively impacted by $3.5 billion due to certain infrequent or non-operating factors, primarily explained by:

- a non-cash, net unrealized gain of $1.2 billion in 2025, compared with a net unrealized loss of $2.2 billion in 2024, reflecting changes in the mark-to-market value of derivative financial instruments used to manage foreign exchange and commodity price risks; and
- the absence in 2025 of $105 million severance costs as a result of a workforce reduction in February 2024.

After taking into consideration the non-operating factors above, we saw a $461 million decrease in EBITDA that is primarily explained by:

- higher realized foreign exchange losses on hedge settlements in 2025; and
- the absence in 2025 of interest income from cash pre-funding related to the Acquisitions.

GROWTH PROJECTS - COMMERCIALLY SECURED PROJECTS

The following table summarizes the status of our material commercially secured projects, organized by business segment:

		Enbridge's Ownership Interest	Estimated Capital Cost[1]	Expenditures to Date[2]	Status[2]	Expected In-Service Date
(Canadian dollars, unless stated otherwise)						
LIQUIDS PIPELINES						
1.	Mainline Optimization Phase 1	100%	US$1.4 billion	US$39 million	Pre-construction	2027
2.	Southern Illinois Connector	100%[3]	US$0.5 billion	No significant expenditures to date	Pre-construction	2028
3.	Pelican CO_2 Hub	50%	US$0.3 billion	No significant expenditures to date	Pre-construction	2029
GAS TRANSMISSION						
4.	Texas Eastern Modernization	100%	US$0.4 billion	US$273 million	Various stages	2025 - 2026
5.	T-North Expansion (Aspen Point)	100%[4]	$1.2 billion	$788 million	Under construction	2026
6.	Tennessee Ridgeline Expansion	100%	US$1.4 billion	US$506 million	Under construction	2026
7.	Woodfibre LNG[5]	30%	US$2.9 billion	US$1.5 billion	Under construction	2027
8.	T-South Expansion (Sunrise)	100%[4]	$4.0 billion	$540 million	Pre-construction	2028
9.	T-North Expansion (Birch Grove)	100%[4]	$0.4 billion	$23 million	Pre-construction	2028
10.	Canyon System Pipelines	100%	US$1.0 billion	US$154 million	Pre-construction	2029
11.	Algonquin Gas Transmission Enhancement	100%	US$0.3 billion	No significant expenditures to date	Pre-construction	2029
12.	USGC Storage Growth Program	100%	US$0.5 billion	No significant expenditures to date	Pre-construction	2028 - 2033
GAS DISTRIBUTION AND STORAGE						
13.	Moriah Energy Center[6]	100%	US$0.6 billion	US$368 million	Under construction	2027
14.	T-15 Reliability Project[6,7]	100%	US$0.7 billion	US$98 million	Pre-construction	2027 - 2028
RENEWABLE POWER GENERATION						
15.	Sequoia Solar	100%	US$1.1 billion	US$796 million	Various stages	2025 - 2026
16.	Clear Fork Solar	100%	US$0.9 billion	US$198 million	Under construction	2027
17.	Easter	100%	US$0.4 billion	US$104 million	Pre-construction	2026 - 2027
18.	Cowboy Phase 1	100%	US$1.2 billion	No significant expenditures to date	Pre-construction	2027
19.	Courseulles (Calvados) Offshore Wind[8]	21.7%	$1.0 billion (€0.6 billion)	$444 million (€303 million)	Under construction	2027

1 These amounts are estimates and are subject to upward or downward adjustment based on various factors. Where appropriate, the amounts reflect our share of joint venture projects.
2 Expenditures to date and status of the project are determined as at December 31, 2025.

3 Includes amounts for the construction of the Southern Illinois Connector Pipeline, which is expected to be 50% jointly-owned with Energy Transfer, costs to upgrade the Energy Transfer Crude Oil Pipeline, in which we have a 27.6% ownership interest, as well as amounts fully attributable to Enbridge.
4 Our redeemable noncontrolling interest holder, the First Nations Partnership, will have the opportunity to participate in designated capital programs once they have been completed or substantially completed. As a result, our ownership interest in the program(s) may change in future periods.
5 Our expected investment is approximately US$2.3 billion, with the remainder financed through non-recourse project level debt.
6 Previously approved projects that were acquired by Enbridge through the acquisition of PSNC.
7 Includes approved capital costs for the second phase of the project which involves installation of additional compression to add capacity and is expected to go into service in 2028.
8 Our investment is approximately $0.3 billion, with the remainder financed through non-recourse project level debt.

Risks related to the development and completion of growth projects are described in Part I. *Item 1A. Risk Factors*.

LIQUIDS PIPELINES

- **Mainline Optimization Phase 1 -** The Mainline Optimization Phase 1 project is intended to support growing customer demand and long-term production growth in Western Canada, increasing deliveries of Canadian heavy oil to key refining markets in the US Midwest and US Gulf Coast (USGC). The project is expected to add 150 and 100 thousand barrels per day of capacity to our Mainline System and Flanagan South Pipeline (FSP), respectively, through increased horsepower, upstream optimizations and terminal enhancements. The FSP expansion is underpinned by long-term take-or-pay contracts providing full-path service from Edmonton, Alberta to Houston, Texas. In addition, the majority of existing customers also elected to extend their existing FSP full-path contracts beyond 2040. The project is expected to enter service in 2027.

- **Southern Illinois Connector -** The construction of a new 24-inch pipeline from Wood River to Patoka, Illinois, connecting the Platte Pipeline to our jointly-owned Energy Transfer Crude Oil Pipeline. In addition, the project includes new pump stations to provide incremental capacity to the Platte system. Incremental volumes are secured under long-term take-or-pay agreements with investment grade customers. The project has an expected in-service date in 2028.

- **Pelican CO_2 Hub -** A 50/50 joint venture with a subsidiary of Occidental Petroleum Corporation (Oxy) to design, construct and operate a carbon dioxide transportation and sequestration hub in the Louisiana Mississippi River corridor. Oxy will manage the sequestration portions of the project, while Enbridge will manage the pipeline. Development is supported by a long-term take-or-pay offtake agreement with an investment grade counterparty and the facility is expected to enter service in 2029.

GAS TRANSMISSION

- **Texas Eastern Modernization -** The modernization of compression facilities in Pennsylvania and New Jersey to increase safety and reliability, as well as to reduce associated greenhouse gas emissions at multiple sites on our Texas Eastern system. The program has entered into service in stages over a period of years beginning in 2024, with all phases expected to be completed in 2026.

- **T-North Expansion (Aspen Point) -** An expansion of our BC Pipeline system in northern BC that includes pipeline looping, additional compressor units and ancillary station modifications to support 535 million cubic feet per day (mmcf/d) of additional capacity. This expansion is expected to serve growing regional demand for natural gas and potential West Coast LNG exports and is underpinned by a cost-of-service commercial model with a target in-service date in 2026.

- **Tennessee Ridgeline Expansion -** An expansion of the East Tennessee Natural Gas system that will provide additional natural gas for the Tennessee Valley Authority (TVA) to support the replacement of an existing coal-fired power plant as TVA continues to transition its power generation mix towards lower-carbon fuels. The proposed scope includes the installation of approximately 125 miles of 30-inch pipeline looping, one electric-powered compressor station and an 8-megawatt (MW) behind-the-meter solar array. We expect the project to enter service in 2026.

- **Woodfibre LNG Project -** Liquefaction and floating storage facilities in Squamish, BC, and an expansion of our BC Pipeline system, the construction of which is executed by our partner. Enbridge holds a noncontrolling equity interest in the project which is expected to be placed into service in 2027.

  Enbridge and its partners have agreed to updated commercial terms for the Woodfibre LNG Project. The preferred return will be set closer to completion of construction, de-risking Enbridge's return on capital, and our expected share of capital costs was updated in 2025.

- **T-South Expansion (Sunrise) -** An expansion of our BC Pipeline system's T-South section that includes pipeline looping, additional compressor units and ancillary station modifications to support 300 mmcf/d of additional capacity. This expansion is driven primarily by an anticipated shortfall in capacity to deliver gas to the BC Lower Mainland and US Pacific Northwest markets following the commencement of deliveries to the Woodfibre LNG Project. The project is underpinned by a cost-of-service commercial model and is expected to be placed into service in 2028. In 2026, the CER recommended the project for approval to the Government of Canada's Governor in Council.

- **T-North Expansion (Birch Grove) -** An expansion of our BC Pipeline system in northern BC that includes pipeline looping and ancillary station modifications to support 178 mmcf/d of additional capacity. The project is underpinned by a cost-of-service commercial model with a target in-service date in 2028. This expansion is driven by the need for natural gas producers in northeastern BC to access markets for their growing production, mainly from the prolific Montney formation. We expect to file our regulatory application for this project with the CER in the second quarter of 2026.

- **Canyon System Pipelines -** The construction of two new offshore pipelines and additional crude oil and natural gas pipeline extensions to support bp's Kaskida and Tiber offshore developments in the USGC. This will include a 24/26-inch oil pipeline connecting to Shell Pipeline Company LP's Green Canyon 19 Platform and a 12-inch gas pipeline connecting to our existing Magnolia Gas Gathering Pipeline. The project is expected to enter service in 2029.

- **Algonquin Gas Transmission Enhancement -** An enhancement of our Algonquin Pipeline to serve incremental demand across the northeastern US. The project is anticipated to enhance supply reliability and improve affordability by reducing winter price volatility for customers. We expect the project to enter service in 2029.

- **USGC Storage Growth Program -** An expansion of our Egan Hub and Moss Bluff natural gas storage facilities in the USGC, to provide 16 billion cubic feet (Bcf) and 7 Bcf of new site capacity, respectively. Egan Hub will be expanded over two phases, with each phase expected to enter service in 2030 and 2033, respectively. The expansion of our Moss Bluff facility is expected to enter service in 2028. These projects are expected to improve site injection and withdrawal rates, optimizing existing capacity, and to offer storage capacity to USGC LNG facilities during periods of high demand.

GAS DISTRIBUTION AND STORAGE

- **Moriah Energy Center -** The construction of an LNG facility in Person County, North Carolina with 2 bcf of storage capacity. The facility is expected to enhance system reliability and to address supply constraints due to customer growth, and will be designed with trucking capabilities to support other LNG facilities. The project has an expected in-service date in 2027.

- **T-15 Reliability Project -** Includes the construction of 45 miles of transmission pipe, a compressor station, and associated metering and regulation facilities in Rockingham, Caswell and Person counties in North Carolina. The project has a two-phased completion in 2027 and 2028.

RENEWABLE POWER GENERATION

- **Sequoia Solar -** An 815 MW solar farm located approximately 150 miles west of Dallas, Texas. The first phase of the project was completed in the fourth quarter of 2025, with the second phase expected to enter service in late 2026. Project revenues are underpinned by long-term fixed price power purchase agreements (PPA).

- **Clear Fork Solar -** A 600 MW solar farm located near San Antonio, Texas, fully contracted under a long-term offtake agreement. The project has an expected in-service date in 2027.

- **Easter -** A 152 MW onshore wind project near Amarillo, Texas, fully contracted under a long-term offtake agreement. The two-phased project is expected to achieve completion in 2026 and 2027.

- **Cowboy Phase 1 -** A 365 MW solar farm and an on-site battery energy storage system (BESS), both located near Cheyenne, Wyoming. Renewable power generated by this project is fully contracted under a long-term offtake agreement and BESS capacity is contracted through a long-term fixed-price battery tolling agreement. BESS is currently approved for 135 MW, expandable up to 200 MW with further utility review and approval. Both components of the project are expected to fully enter service in 2027.

- **Courseulles (Calvados) Offshore Wind -** An offshore wind project located off the northwest coast of France that is expected to generate approximately 448 MW of power. The project has an expected in-service date in 2027 and revenues are underpinned by a 20-year fixed price PPA.

OTHER ANNOUNCED PROJECTS UNDER DEVELOPMENT

LIQUIDS PIPELINES
Mainline Optimization Phase 2
On November 7, 2025, we announced the Mainline Optimization Phase 2 (MLO2) project. MLO2 is expected to provide an additional 250 thousand barrels per day of egress from the Western Canadian Sedimentary Basin, leveraging capacity on our existing assets including the Dakota Access Pipeline, in which we have a 27.6% interest, Line 26 and the Chicap Pipeline system. The project is expected to enter service in 2028 and is subject to finalizing commercial agreements, securing the necessary environmental and regulatory approvals, and meeting investment criteria.

LIQUIDITY AND CAPITAL RESOURCES

The maintenance of financial strength and flexibility is fundamental to our growth strategy, particularly in light of the significant number and size of capital projects currently secured or under development. Access to timely funding from capital markets could be limited by factors outside our control, including but not limited to, financial market volatility resulting from economic and political events both inside and outside North America. To mitigate such risks, we actively manage financial plans and strategies to help ensure we maintain sufficient liquidity to meet routine operating and future capital requirements.
In the near term, we generally expect to utilize cash from operations together with commercial paper issuances and/or credit facility draws and the proceeds of capital market offerings to fund liabilities as they become due, finance capital expenditures and acquisitions and fund debt retirements. We target to maintain sufficient liquidity through securement of committed credit facilities with a diversified group of banks and financial institutions to enable us to fund all anticipated requirements for approximately one year without accessing the capital markets.

Material contractual obligations arising in the normal course of business primarily consist of long-term contracts, annual debt maturities and related interest obligations, rights-of-way and leases. See Part II. *Item 8. Financial Statements and Supplementary Data - Note 17 - Debt, Note 26 - Leases* and *Note 30 - Commitments and Contingencies* for amounts outstanding at December 31, 2025.

Long-term contracts are contracts that we have signed for the purchase of services, pipe and other materials totaling $14.0 billion which are expected to be paid over the next five years. Long-term contracts primarily consist of the following purchase obligations: firm capacity payments for natural gas and crude oil transportation and storage contracts, natural gas purchase commitments and power commitments.

Our financing plan is regularly updated to reflect evolving capital requirements and financial market conditions and identifies a variety of potential sources of debt and equity funding alternatives.

CAPITAL MARKET ACCESS

We enable access to capital markets, subject to market conditions, through maintenance of shelf prospectuses that allow for issuances of long-term debt, equity and other forms of long-term capital when market conditions are attractive. In accordance with our funding plan, we completed the following long-term debt issuances totaling $4.6 billion and US$4.7 billion in 2025.

Entity	Issuance date	Type of issuance	Amount
(millions of Canadian dollars, unless otherwise stated)			
Enbridge Inc.	February 2025	Floating rate notes	$400
Enbridge Inc.	February 2025	Medium-term notes	$2,400
Enbridge Inc.	June 2025	Senior notes	US$2,250
Enbridge Inc.	September 2025	Fixed-to-fixed subordinated notes	$1,000
Enbridge Inc.	November 2025	Senior notes	US$1,500
Enbridge Gas Inc.	September 2025	Medium-term notes	$800
The East Ohio Gas Company	June 2025	Senior notes	US$500
The East Ohio Gas Company	December 2025	Senior notes	US$400

Credit Facilities and Liquidity

To ensure ongoing liquidity and to mitigate the risk of capital market disruption, we maintain access to funds through committed bank credit facilities and actively manage our bank funding sources to optimize pricing and other terms. 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.

As at December 31, 2025, our net available liquidity totaled $10.8 billion (December 31, 2024 - $14.4 billion), consisting of available credit facilities of $9.7 billion (December 31, 2024 - $12.6 billion) and unrestricted cash and cash equivalents of $1.1 billion (December 31, 2024 - $1.8 billion) as reported in the Consolidated Statements of Financial Position.

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.

Cash flow growth, ready access to liquidity from diversified sources and a stable business model have enabled us to manage our credit profile. We actively monitor and manage key financial metrics with the objective of sustaining investment grade credit ratings from the major credit rating agencies and ongoing access to bank funding and term debt capital on attractive terms. Key measures of financial strength that are closely managed include the ability to service debt obligations from operating cash flow and the ratio of debt to EBITDA.

There are no material restrictions on our cash. Total restricted cash of $83 million, as reported in the Consolidated Statements of Financial Position, primarily includes reinsurance security, cash collateral, future pipeline abandonment costs collected and held in trust, amounts received in respect of specific shipper commitments and capital projects. Cash and cash equivalents held by certain subsidiaries may not be readily accessible for alternative uses by us.

Excluding current maturities of long-term debt, as at December 31, 2025 and December 31, 2024, we had negative working capital positions of $2.8 billion and $2.9 billion, respectively. In both 2025 and 2024, the major contributing factors to the negative working capital position were the current liabilities associated with our growth capital program. To address this negative working capital position, we maintain significant liquidity in the form of committed credit facilities and other sources as previously discussed, which enable the funding of liabilities as they become due.

SOURCES AND USES OF CASH

Year ended December 31,	**2025**	2024	2023
(millions of Canadian dollars)			
Operating activities	**12,270**	12,600	14,201
Investing activities	**(10,503)**	(20,363)	(6,043)
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

Significant sources and uses of cash for the years ended December 31, 2025 and 2024 are summarized below:

Operating Activities

Typically, the primary factors impacting cash provided by operating activities year-over-year include changes in our operating assets and liabilities in the normal course due to various factors, including the impact of fluctuations in commodity prices and activity levels on working capital within our business segments, the timing of tax payments, as well as timing of cash receipts and payments generally. Refer to Part II. *Item 8. Financial Statements and Supplementary Data - Note 28 - Changes in Operating Assets and Liabilities.* Cash provided by operating activities is also impacted by changes in earnings and certain infrequent or other non-operating factors, as discussed in *Results of Operations*, as well as Distributions from equity investments.

Investing Activities
Cash used in investing activities primarily relates to capital expenditures to execute our capital program, which is further described in *Growth Projects - Commercially Secured Projects*. The timing of project approval, construction and in-service dates impacts the timing of cash requirements. Cash used in investing activities is also impacted by acquisitions, dispositions, and changes in contributions to, and distributions from, our equity investments.

A summary of cash additions to property, plant and equipment for the years ended December 31, 2025, 2024 and 2023 is set out below:

Year ended December 31,	**2025**	2024	2023
(millions of Canadian dollars)			
Liquids Pipelines	**1,358**	1,157	1,158
Gas Transmission	**3,176**	2,453	1,890
Gas Distribution and Storage	**3,318**	2,381	1,451
Renewable Power Generation	**947**	661	100
Eliminations and Other	**174**	59	55
Total capital expenditures	**8,973**	6,711	4,654

2025
The decrease in cash used in investing activities primarily resulted from the following factors:

- the absence in 2025 of the acquisitions of EOG, Questar, PSNC, and Tomorrow RNG;
- the absence in 2025 of the acquisitions of equity interests in the Whistler Parent JV and DBR and contributions to our Fox Squirrel Solar investment; partially offset by
- the absence in 2025 of proceeds received from the disposition of our interests in the Alliance Pipeline, Aux Sable, and NRGreen Power Limited Partnership (NRGreen); and
- a full year of capital expenditures from EOG, Questar, and PSNC, and higher capital expenditures from growth projects in our Gas Transmission and Renewable Power Generation segments.

2024
The increase in cash used in investing activities primarily resulted from the following factors:

- the acquisitions of EOG, Questar, PSNC, and Tomorrow RNG in 2024;
- increased capital expenditures from the acquisitions of EOG, Questar and PSNC and from growth projects in our Gas Transmission segment; and
- the acquisition of an equity interest in the Whistler Parent JV and DBR and contributions to our Fox Squirrel Solar investment in 2024; partially offset by
- proceeds received from the dispositions of our interests in the Alliance Pipeline, Aux Sable, and NRGreen in 2024.

Financing Activities
Cash used in financing activities primarily relates to issuances and repayments of external debt, as well as transactions with our common and preference shareholders relating to dividends, share issuances, and share redemptions. Cash used in financing activities is also impacted by changes in distributions to, and contributions from, noncontrolling interests and redeemable noncontrolling interest.

2025
The increase in cash used in financing activities primarily resulted from the following factors:

- lower commercial paper and credit facility draws in 2025 compared to 2024; and
- the absence in 2025 of the at-the-market program, which resulted in the issuance of 51,298,629 common shares for aggregate net proceeds of $2.5 billion in 2024; partially offset by
- higher long-term debt issuances in 2025 compared to 2024, and
- proceeds of $712 million, net of transaction costs, received from the First Nations Partnership for their noncontrolling interest investment in our BC pipeline system.

2024
The increase in cash provided by financing activities primarily resulted from the following factors:

- net commercial paper and credit facility draws in 2024 compared to net repayments in 2023;
- the at-the-market program, which resulted in the issuance of 51,298,629 common shares for aggregate net proceeds of $2.5 billion in 2024; and
- lower net repayments of short-term borrowings in 2024 compared to 2023; partially offset by
- higher long-term debt repayments and lower long-term debt issuances in 2024 compared to 2023;
- the absence in 2024 of the public offering of common shares, which closed on September 8, 2023 for gross proceeds of $4.6 billion; and
- increased common share dividend payments primarily due to the increase in our common share dividend rate and an increase in the number of common shares outstanding.

OFF-BALANCE SHEET ARRANGEMENTS
We enter into guarantee arrangements in the normal course of business to facilitate commercial transactions with third parties and can include financial guarantees, stand-by letters of credit, debt guarantees, surety bonds and indemnifications. Please see Part II. *Item 8. Financial Statements and Supplementary Data - Note 31 - Guarantees* for further discussion of guarantee arrangements.

We do not have material off-balance sheet financing entities or structures, except for guarantee arrangements and financings entered into for our equity investments. For additional information on these commitments, please refer to Part II. *Item 8. Financial Statements and Supplementary Data - Note 30 - Commitments and Contingencies and Note 12 - Variable Interest Entities.*

We do not have material off-balance sheet arrangements that have or are reasonably likely to have a current or future effect on our financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources.

OUTSTANDING PREFERENCE SHARES

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.

DIVIDENDS

We have paid common share dividends in every year since we became a publicly traded company in 1953. In December 2025, we announced a 3% increase in our quarterly dividend to $0.9700 per common share, or $3.88 annualized, effective with the dividend payable on March 1, 2026, thereby declaring a dividend increase for 31 straight years.

For the years ended December 31, 2025 and 2024, total dividends paid in cash were $8.2 billion and $7.9 billion, respectively, which are reflected in Cash Flows from Financing Activities in the Consolidated Statements of Cash Flows.

On December 2, 2025, our Board of Directors declared the following quarterly dividends. All dividends are payable on March 1, 2026 to shareholders of record on February 17, 2026.

	Dividend per share
Common Shares[1]	$0.9700
Preference Shares, Series A	$0.34375
Preference Shares, Series B	$0.32513
Preference Shares, Series D	$0.33825
Preference Shares, Series F	$0.34613
Preference Shares, Series G[2]	$0.29836
Preference Shares, Series H	$0.38200
Preference Shares, Series I[3]	$0.27432
Preference Shares, Series L	US$0.36612
Preference Shares, Series N	$0.41850
Preference Shares, Series P	$0.36988
Preference Shares, Series R	$0.39463
Preference Shares, Series 1	US$0.41898
Preference Shares, Series 3	$0.33050
Preference Shares, Series 4[4]	$0.29034
Preference Shares, Series 5	US$0.41769
Preference Shares, Series 7	$0.37425
Preference Shares, Series 9	$0.35450
Preference Shares, Series 11	$0.34231
Preference Shares, Series 13	$0.33719
Preference Shares, Series 15	$0.35163
Preference Shares, Series 19	$0.38825

1 The quarterly dividend per common share was increased 3% to $0.9700 from $0.9425, effective March 1, 2026.

2 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.

3 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.

4 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.

SUMMARIZED FINANCIAL INFORMATION

On January 22, 2019, Enbridge entered into supplemental indentures with its wholly-owned subsidiaries, Spectra Energy Partners, LP (SEP) and EEP (together, the Partnerships), pursuant to which Enbridge fully and unconditionally guaranteed, on a senior unsecured basis, the payment obligations of the Partnerships with respect to the outstanding series of notes issued under the respective indentures of the Partnerships. Concurrently, the Partnerships entered into a subsidiary guarantee agreement pursuant to which they fully and unconditionally guaranteed, on a senior unsecured basis, the outstanding series of senior notes of Enbridge. The Partnerships have also entered into supplemental indentures with Enbridge pursuant to which the Partnerships have issued full and unconditional guarantees, on a senior unsecured basis, of senior notes issued by Enbridge subsequent to January 22, 2019. As a result of the guarantees, holders of any of the outstanding guaranteed notes of the Partnerships (the Guaranteed Partnership Notes) are in the same position with respect to the net assets, income and cash flows of Enbridge as holders of Enbridge's outstanding guaranteed notes (the Guaranteed Enbridge Notes), and vice versa. Other than the Partnerships, Enbridge subsidiaries (including the subsidiaries of the Partnerships, collectively, the Subsidiary Non-Guarantors), are not parties to the subsidiary guarantee agreement and have not otherwise guaranteed any of Enbridge's outstanding series of senior notes.

Consenting SEP notes and EEP notes under Guarantees

SEP Notes[1]	EEP Notes[2]
3.38% Senior Notes due 2026	5.95% Notes due 2033
5.95% Senior Notes due 2043	6.30% Notes due 2034
4.50% Senior Notes due 2045	7.50% Notes due 2038
	5.50% Notes due 2040
	7.38% Notes due 2045

1 As at December 31, 2025, the aggregate outstanding principal amount of SEP notes was approximately US$1.7 billion.
2 As at December 31, 2025, the aggregate outstanding principal amount of EEP notes was approximately US$1.9 billion.

Enbridge Notes under Guarantees

USD Denominated[1]	CAD Denominated[2]
1.60% Senior Notes due 2026	3.20% Senior Notes due 2027
5.90% Senior Notes due 2026	5.70% Senior Notes due 2027
4.25% Senior Notes due 2026	3.55% Senior Notes due 2028
5.25% Senior Notes due 2027	4.90% Senior Notes due 2028
3.70% Senior Notes due 2027	6.10% Senior Notes due 2028
4.60% Senior Notes due 2028	Floating Rate Senior Notes due 2028
6.00% Senior Notes due 2028	2.99% Senior Notes due 2029
4.20% Senior Notes due 2028	4.21% Senior Notes due 2030
5.30% Senior Notes due 2029	3.90% Senior Notes due 2030
3.13% Senior Notes due 2029	7.22% Senior Notes due 2030
4.90% Senior Notes due 2030	7.20% Senior Notes due 2032
6.20% Senior Notes due 2030	6.10% Sustainability-Linked Senior Notes due 2032
4.50% Senior Notes due 2031	5.36% Sustainability-Linked Senior Notes due 2033
5.70% Sustainability-Linked Senior Notes due 2033	3.10% Sustainability-Linked Senior Notes due 2033
2.50% Sustainability-Linked Senior Notes due 2033	4.73% Senior Notes due 2034
5.63% Senior Notes due 2034	4.56% Senior Notes due 2035
5.55% Senior Notes due 2035	5.57% Senior Notes due 2035
5.20% Senior Notes due 2035	5.75% Senior Notes due 2039
4.50% Senior Notes due 2044	5.12% Senior Notes due 2040
5.50% Senior Notes due 2046	4.24% Senior Notes due 2042
4.00% Senior Notes due 2049	4.57% Senior Notes due 2044
3.40% Senior Notes due 2051	4.87% Senior Notes due 2044
6.70% Senior Notes due 2053	4.10% Senior Notes due 2051
5.95% Senior Notes due 2054	6.51% Senior Notes due 2052
	5.76% Senior Notes due 2053
	5.32% Senior Notes due 2054
	4.56% Senior Notes due 2064

1 *As at December 31, 2025, the aggregate outstanding principal amount of the Enbridge US dollar-denominated notes was approximately US$19.8 billion.*

2 *As at December 31, 2025, the aggregate outstanding principal amount of the Enbridge Canadian dollar-denominated notes was approximately $$14.5 billion.*

Rule 3-10 of the US SEC Regulation S-X provides an exemption from the reporting requirements of the Exchange Act for fully consolidated subsidiary issuers of guaranteed securities and subsidiary guarantors and allows for summarized financial information in lieu of filing separate financial statements for each of the Partnerships.

The following Summarized Combined Statement of Earnings and Summarized Combined Statements of Financial Position combines the balances of SEP, EEP, and Enbridge.

Summarized Combined Statement of Earnings

Year ended December 31,	**2025**
(millions of Canadian dollars)	
Operating loss	**(63)**
Earnings	**2,826**
Earnings attributable to common shareholders	**2,407**

Summarized Combined Statements of Financial Position

December 31,	**2025**	2024
(millions of Canadian dollars)		
Cash and cash equivalents	**391**	2,000
Accounts receivable from affiliates	**3,873**	3,901
Short-term loans receivable from affiliates	**6,239**	3,892
Other current assets	**467**	499
Long-term loans receivable from affiliates	**46,858**	54,416
Other long-term assets	**1,994**	2,139
Accounts payable to affiliates	**2,079**	2,252
Short-term loans payable to affiliates	**2,082**	1,188
Trade payables and accrued liabilities	**537**	661
Other current liabilities	**6,990**	8,047
Long-term loans payable to affiliates	**34,488**	36,576
Other long-term liabilities	**67,004**	62,642

The Guaranteed Enbridge Notes and the Guaranteed Partnership Notes are structurally subordinated to the indebtedness of the Subsidiary Non-Guarantors in respect of the assets of those Subsidiary Non-Guarantors.

Under US bankruptcy law and comparable provisions of state fraudulent transfer laws, a guarantee can be voided, or claims may be subordinated to all other debts of that guarantor if, among other things, the guarantor, at the time the indebtedness evidenced by its guarantee or, in some states, when payments become due under the guarantee:

- received less than reasonably equivalent value or fair consideration for the incurrence of the guarantee and was insolvent or rendered insolvent by reason of such incurrence;
- was engaged in a business or transaction for which the guarantor’s remaining assets constituted unreasonably small capital; or
- intended to incur, or believed that it would incur, debts beyond its ability to pay those debts as they mature.

The guarantees of the Guaranteed Enbridge Notes contain provisions to limit the maximum amount of liability that the Partnerships could incur without causing the incurrence of obligations under the guarantee to be a fraudulent conveyance or fraudulent transfer under US federal or state law.

Each of the Partnerships is entitled to a right of contribution from the other Partnership for 50% of all payments, damages and expenses incurred by that Partnership in discharging its obligations under the guarantees for the Guaranteed Enbridge Notes.

Under the terms of the guarantee agreement and applicable supplemental indentures, the guarantees of either of the Partnerships of any Guaranteed Enbridge Notes will be unconditionally released and discharged automatically upon the occurrence of any of the following events:

- any direct or indirect sale, exchange or transfer, whether by way of merger, sale or transfer of equity interests or otherwise, to any person that is not an affiliate of Enbridge, of any of Enbridge's direct or indirect limited partnership of other equity interests in that Partnership as a result of which the Partnership ceases to be a consolidated subsidiary of Enbridge;
- the merger of that Partnership into Enbridge or the other Partnership or the liquidation and dissolution of that Partnership;
- the repayment in full or discharge or defeasance of those Guaranteed Enbridge Notes, as contemplated by the applicable indenture or guarantee agreement;
- with respect to EEP, the repayment in full or discharge or defeasance of each of the consenting EEP notes listed above;
- with respect to SEP, the repayment in full or discharge or defeasance of each of the consenting SEP notes listed above; or
- with respect to any series of Guaranteed Enbridge Notes, with the consent of holders of at least a majority of the outstanding principal amount of that series of Guaranteed Enbridge Notes.

The guarantee obligations of Enbridge will terminate with respect to any series of Guaranteed Partnership Notes if that series is discharged or defeased.

The Partnerships also guarantee the obligations of Enbridge under its existing credit facilities.

LEGAL AND OTHER UPDATES

LINE 5 EASEMENT (BAD RIVER BAND)

On July 23, 2019, the Bad River Band of the Lake Superior Tribe of Chippewa Indians (the Band) filed a complaint in the US District Court for the Western District of Wisconsin (the Court) over our Line 5 pipeline and right-of-way across the Bad River Reservation (the Reservation). Only a small portion of the total easements across 12 miles of the Reservation are at issue. The Band alleges that the continued operation of Line 5 across the Reservation constitutes a public nuisance under federal and state law and that the pipeline is in trespass on certain tracts of land where the Band holds ownership interests. The complaint seeks an Order prohibiting us from using Line 5 to transport crude oil and related liquids across the Reservation and requiring removal of the pipeline from the Reservation. Subsequently amended versions of the complaint also seek recovery of profits-based damages based on an unjust enrichment theory. Enbridge has responded to each claim in the initial and amended complaints with answers, defenses and counterclaims.

On August 29, 2022, the Government of Canada released a statement formally invoking the dispute settlement provisions of the Agreement Between the US and Canada Concerning Transit Pipelines, 28 U.S.T. 7449 (1977) (1977 Transit Pipelines Treaty) in respect of this litigation, reiterating its concerns about the uninterrupted transmission of hydrocarbons through Line 5.

On September 7, 2022, the Court issued a decision on cross-motions for summary judgment. The Court determined that the Band's nuisance claim raised factual issues that could not be resolved on summary judgment. The Court further determined that Enbridge is in trespass on 12 parcels on the Reservation and that the Band is entitled to some measure of profits-based damages and injunctive relief, with the level of damages and scope of the injunction to be determined at trial. The trial was held from October 24 to November 1, 2022.

On May 9, 2023, the Band filed an Emergency Motion for Injunctive Relief requesting that the Court order Enbridge to purge and shutdown Line 5 on the Reservation due to significant erosion at a river bend known as Meander. After a hearing on May 18, 2023, the Court stated the Band had not demonstrated imminent harm and indicated a final ruling would follow.

On June 26, 2023, the Court issued its Final Order ruling that: (1) Enbridge shall adopt and implement its 2022 Monitoring and Shutdown Plan with the Court's modifications by July 5, 2023; (2) Enbridge owes the Band $5,151,668 for past trespass on the 12 allotted parcels; (3) Enbridge must continue to make quarterly payments using the Court's formula, for as long as Line 5 operates in trespass on those parcels (approximately $400,000 per year); (4) Enbridge must cease operation of Line 5 on any parcel within the Band's tribal territory lacking a valid right-of-way by June 16, 2026 and thereafter arrange prompt, reasonable remediation at those sites; and (5) The Court declined to allow for completion of the Wisconsin Relocation Project prior to having to cease operations. The Final Judgment was entered on June 29, 2023.

Enbridge filed its Notice of Appeal on June 30, 2023 and the Band filed its Notice of Cross Appeal on July 27, 2023. On December 12, 2023, the US Court of Appeals for the Seventh Circuit requested that the US file a brief in the appeal as amicus curiae to address the effect of 1977 Transit Pipelines Treaty, and any other issues that the US believes to be material. The US filed its brief on April 8, 2024. As invited by the Court of Appeals, on April 29, 2024, Enbridge and the Band filed responses to the US amicus brief. A decision from the Court of Appeals is expected in early 2026. On January 27, 2026, Enbridge filed a Motion to Stay or Modify the portion of the Court’s June 29, 2023 Final Judgment requiring Enbridge to cease operation of Line 5 on any parcel without a valid right-of-way by June 16, 2026.

In March 2025, after receiving authorizations from tribal, federal, and state agencies, an erosion mitigation project was successfully installed at the Meander.

MICHIGAN LINE 5 DUAL PIPELINES - STRAITS OF MACKINAC EASEMENT
Michigan Attorney General Lawsuit
In 2019, the Michigan Attorney General initiated legal action in the Michigan Ingham County Circuit Court (Michigan Circuit Court) seeking to invalidate the 1953 easement that authorizes the operation of Enbridge’s Line 5 pipeline in the Straits of Mackinac. The Attorney General’s case was later moved to US federal court in December 2021, following a November 16, 2021 ruling which held that the similar (and now dismissed) 2020 lawsuit brought by the Governor of Michigan to force the shutdown of Line 5 raised important federal issues that should be heard in federal court.

In June 2024, the US Court of Appeals for the Sixth Circuit (Sixth Circuit) ruled that the case should proceed in state court. Enbridge’s request for a rehearing was denied in August 2024. Oral argument on long-standing cross motions for summary disposition was held in January 2025 in the Michigan Circuit Court. A decision is expected in 2026.

Separately, in January 2025, Enbridge petitioned the US Supreme Court to review the Sixth Circuit’s decision. The Court granted the petition in June 2025. Briefing is complete, with oral argument and a decision expected in 2026. In the interim, Enbridge requested that the Michigan Circuit Court pause proceedings pending the US Supreme Court’s ruling. This motion was denied.

In parallel, the US Army Corps of Engineers (Army Corps) announced in April 2025 that the Line 5 Tunnel Project qualified for review under emergency and special processing procedures. On November 13, 2025, the Army Corps issued a Supplemental Draft Environmental Impact Statement with a public comment period ending in December 2025. On February 6, 2026, the Army Corps issued its Final Environmental Impact System. We expect a Record of Decision to be issued in 2026.

Enbridge Lawsuit
On November 24, 2020, Enbridge filed a complaint in the US District Court in the Western District for Michigan (US District Court) seeking declaratory and injunctive relief to prevent the Governor of Michigan and Director of the Michigan Department of Natural Resources (Michigan State Officials) from interfering with the continued operation of Line 5. The Government of Canada has reiterated its support for the pipeline, emphasizing the relevance of the 1977 Transit Pipelines Treaty and the matter’s importance to Canada.

In January 2022, Michigan State Officials moved to dismiss the case, and Enbridge filed for summary judgment. On July 5, 2024, the US District Court denied the state's motion to dismiss, prompting an immediate appeal to the Sixth Circuit. The case was stayed pending the outcome of the appeal.

On April 23, 2025, the Sixth Circuit affirmed the US District Court's ruling and a petition for rehearing en banc was denied on June 16, 2025. On June 24, 2025, the case was administratively transferred back to the US District Court and Michigan State Officials filed their Answer to Enbridge's complaint.

A case management order was issued on July 14, 2025, setting out a briefing schedule for Enbridge's summary judgment motion and the state's motion to abstain. On September 12, 2025, the US filed a statement of interest in the case. Briefing concluded on October 10, 2025 and oral argument was held on November 12, 2025.

On December 17, 2025, the US District Court entered judgment in Enbridge's favor and denied the Michigan State Officials motion to abstain or stay the federal action. In January 2026, the Michigan State Officials filed an appeal, and shortly thereafter in the Michigan Circuit Court, Enbridge and the Michigan Attorney General filed a stipulation to stay the Michigan Attorney General Lawsuit, pending the Sixth Circuit's decision.

DAKOTA ACCESS PIPELINE

We hold an effective 27.6% interest in the Bakken Pipeline System, which includes the Dakota Access Pipeline (DAPL). The Standing Rock Sioux Tribe and the Cheyenne River Sioux Tribe filed lawsuits in 2016 with the US Court for the District of Columbia (the District Court) challenging the Army Corps' easement for DAPL, citing concerns over the adequacy of the Army Corps' environmental review and tribal consultation process. The Oglala Sioux and Yankton Sioux Tribes also filed lawsuits alleging similar claims in 2018. In 2017 and again in 2020, the District Court found deficiencies in the Army Corps' environmental assessments and ordered the preparation of a full Environmental Impact Statement (EIS).

In July 2020, the District Court vacated the easement and ordered the pipeline shut down, but that order was stayed by the US Court of Appeals for the District of Columbia. In January 2021, the US Court of Appeals upheld the requirement for an EIS and confirmed the easement's vacatur, though it ruled that DAPL could continue operating absent an injunction. The US Supreme Court declined to review the case, and the Army Corps indicated it would not seek to halt operations during the review process.

On September 8, 2023, the Army Corps released a draft EIS evaluating five alternatives, including continued operation, shutdown, rerouting, and removal of the pipeline. No preferred alternative was identified. The public comment period closed on December 13, 2023.

On December 19, 2025, the Army Corps published the final EIS for DAPL. The final EIS includes an extensive analysis of spill risks from the pipeline, including the pipeline safety record of Energy Transfer Crude Oil Pipeline. The Army Corps must wait 30-days after publication of the final EIS before a Record of Decision and new easement may be issued. Accordingly, a Record of Decision and easement are expected in 2026.

Separately, on October 15, 2024, the Standing Rock Sioux Tribe filed a new complaint in the District Court seeking a permanent injunction against DAPL's operation, alleging that the Army Corps is unlawfully allowing continued operations without a valid easement or compliant Facility Response Plan. Dakota Access, LLC and 13 states intervened in support of continued operations. On March 28, 2025, the District Court dismissed the complaint. The Tribe filed a notice of appeal on May 27, 2025. The appeal process is expected to take six to 12 months.

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.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

Our consolidated financial statements are prepared in accordance with US GAAP, which requires management to make estimates, judgments and assumptions that affect the amounts reported in our consolidated financial statements and accompanying notes. In making judgments and estimates, management relies on external information and observable conditions, where possible, supplemented by internal analysis as required. We believe our most critical accounting policies and estimates discussed below have an impact across the various segments of our business.

GOODWILL IMPAIRMENT

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

ASSET IMPAIRMENT
We evaluate the recoverability of our property, plant and equipment when events or circumstances, such as economic obsolescence, business climate, legal or regulatory changes, or other factors, indicate that we may not recover the carrying amount of our assets. We regularly monitor our businesses, the market and business environments to identify indicators that could suggest an asset may not be recoverable. If it is determined that the carrying value of an asset exceeds its expected undiscounted cash flows, we will assess the fair value of the asset. An impairment loss is recognized when the carrying amount of the asset exceeds its fair value.

With respect to equity method investments, we assess at each balance sheet date whether there is objective evidence that the investment is impaired by completing a qualitative or quantitative analysis of factors impacting the investment. If there is objective evidence of impairment, we determine whether the decline below carrying value is other-than-temporary. If the decline is determined to be other-than-temporary, an impairment charge is recorded in earnings with an offsetting reduction to the carrying value of the investment.

Asset fair value is determined using present value techniques. The determination of fair value using present value techniques requires the use of projections and assumptions regarding future cash flows and weighted average cost of capital. Any changes to these projections and assumptions could result in revisions to the evaluation of the recoverability of the asset and the recognition of an impairment loss in the Consolidated Statements of Earnings.

REGULATORY ACCOUNTING
Certain parts of our businesses are subject to regulation by various authorities including, but not limited to the CER, the FERC, the Alberta Energy Regulator, the BC Energy Regulator, the OEB, the Québec Régie de l'énergie, the Ohio Commission, the North Carolina Commission, the Utah Commission, the Wyoming Commission, and the 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.

Key determinants in the ratemaking process are:

- costs of providing service, including operating costs, capital invested, depreciation expense and taxes;
- allowed rate of return, including the equity component of the capital structure and related income taxes;
- interest costs on the debt component of the capital structure; and
- contract and volume throughput assumptions.

The allowed rate of return is determined in accordance with the applicable regulatory model and may impact our profitability. The rates for a number of our projects are based on a cost-of-service recovery model that follows the regulators' authoritative guidance. Under the cost-of-service tolling methodology, we calculate tolls based on forecast volumes and cost. A difference between forecast and actual results causes an over- or under-recovery in any given year.

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.

As at December 31, 2025 and 2024, our regulatory assets totaled $7.6 billion and our regulatory liabilities totaled $6.7 billion in both years.

DEPRECIATION

Depreciation of property, plant and equipment, our largest asset with a net book value at December 31, 2025 and 2024, of $131.6 billion and $131.1 billion, respectively, is charged in accordance with two primary methods. 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.

When it is determined that the estimated service life of an asset no longer reflects the expected remaining period of benefit, prospective changes are made to the estimated service life. Estimates of useful lives are based on third-party engineering studies, experience and/or industry practice. There are a number of assumptions inherent in estimating the service lives of our assets including the level of development, exploration, drilling, reserves and production of crude oil and natural gas in the supply areas served by our pipelines, as well as the demand for crude oil and natural gas and the integrity of our systems. Changes in these assumptions could result in adjustments to the estimated service lives, which could result in material changes to depreciation expense in future periods in any of our business segments. For certain rate-regulated operations, depreciation rates are approved by the regulator and the regulator may require periodic studies or technical updates on useful lives which may change depreciation rates.

The successful efforts method of accounting is used for cost-of-service reserves developed and produced by Wexpro for gas utility affiliate, Questar. 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.

PENSION AND OTHER POSTRETIREMENT BENEFITS

We use certain assumptions relating to the calculation of defined benefit pension and other postretirement liabilities and net periodic benefit costs. These assumptions comprise management's best estimates of expected return on plan assets, future salary levels, other cost escalations, retirement ages of employees, and other actuarial factors including discount rates and mortality. We determine discount rates by reference to rates of high-quality long-term corporate bonds with maturities that approximate the timing of future payments anticipated to be made under each of the respective plans. The expected return on plan assets is determined using market-related values and assumptions on the asset mix consistent with the investment policy relating to the assets and their projected returns. The assumptions are reviewed annually by our independent actuaries. Actual results that differ from results based on assumptions are amortized over future periods and, therefore, could materially affect the expense recognized and the recorded obligation in future periods.

The following sensitivity analysis identifies the impact on the consolidated financial statements for the year ended December 31, 2025 of a 0.5% change in key pension and other postretirement benefits (OPEB) obligation assumptions:

	Canada		United States	
	Obligation	Expense	Obligation	Expense
(millions of Canadian dollars)				
Pension				
Decrease in discount rate	281	7	90	2
Decrease in expected return on assets	—	25	—	10
Decrease in rate of salary increase	(54)	(8)	(18)	(3)
OPEB				
Decrease in discount rate	11	1	7	—
Decrease in expected return on assets	N/A	N/A	—	1

CONTINGENT LIABILITIES

Provisions for claims filed against us are determined on a case-by-case basis. Case estimates are reviewed on a regular basis and are updated as new information is received. The process of evaluating claims involves the use of estimates and a high degree of management judgment. Claims outstanding, the final determination of which could have a material impact on our financial results and certain subsidiaries and investments, are detailed in *Legal and Other Updates* and Part II*. Item 8. Financial Statements and Supplementary Data - Note 30 - Commitments and Contingencies*. In addition, any unasserted claims that later may become evident could have a material impact on our financial results and certain subsidiaries and investments.

ASSET RETIREMENT OBLIGATIONS

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. The discount rates used to estimate the present value of expected future cash flows for the years ended December 31, 2025 ranged from 3.0% to 9.0% (2024 - 1.5% to 9.0%). Asset retirement cost 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, there is insufficient data or information to reasonably determine the timing of settlement for estimating the fair value of the ARO. In these cases, the fair value of ARO is considered indeterminate for accounting purposes, as there is no data or information that can be derived from past practice, industry practice or the estimated economic life of the asset.

In 2009, the CER issued a decision related to the Land Matters Consultation Initiative (LMCI), which required holders of an authorization to operate a pipeline under the *CER Act* to file a proposed process and mechanism to set aside funds to pay for future abandonment costs in respect of the sites in Canada used for the operation of a pipeline. The CER's decision stated that, while pipeline companies are ultimately responsible for the full costs of abandoning pipelines, abandonment costs are a legitimate cost of providing service and are recoverable from the users of the pipeline upon approval by the CER. Following the CER's final approval of the collection mechanism and the set-aside mechanism for LMCI, we began collecting and setting aside funds to cover future abandonment costs effective January 1, 2015. The funds collected are held in trusts in accordance with the CER decision. The funds collected from shippers are reported within Transportation and other services revenues and Restricted long-term investments and cash. Concurrently, we reflect the future abandonment cost as an increase to Operating and administrative expense and Other long-term liabilities.

CHANGES IN ACCOUNTING POLICIES

Refer to Part II. *Item 8. Financial Statements and Supplementary Data - Note 3 - Changes in Accounting Policies.*