2024 Annual Report

ENBRIDGE

Safe. Reliable. Affordable.

All the Above

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended December 31, 2024

or

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from to

Commission file number 001-15254

ENBRIDGE INC.

(Exact Name of Registrant as Specified in Its Charter)

Canada	**98-0377957**
(State or Other Jurisdiction of Incorporation or Organization)	(I.R.S. Employer Identification No.)

200, 425 - 1st Street S.W.
Calgary, Alberta, Canada T2P 3L8
(Address of Principal Executive Offices) (Zip Code)
(403) 231-3900
(Registrant's Telephone Number, Including Area Code)

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Trading Symbol(s)	Name of each exchange on which registered
Common Shares	ENB	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act: **None**

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☒ No ☐

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ☐ No ☒

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files). Yes ☒ No ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company, or an emerging growth company. See the definitions of “large accelerated filer,” “accelerated filer”, “smaller reporting company,” and "emerging growth company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer	☒	Accelerated filer	☐
Non-accelerated filer	☐	Smaller reporting company	☐
Emerging growth company	☐		

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

Indicate by check mark whether the registrant has filed a report on and attestation to its management's assessment of the effectiveness of its internal control over financial reporting under Section 404(b) of the Sarbanes-Oxley Act (15 U.S.C. 7262(b)) by the registered public accounting firm that prepared or issued its audit report. Yes ☒ No ☐

If securities are registered pursuant to Section 12(b) of the Act, indicate by check mark whether the financial statements of the registrant included in the filing reflect the correction of an error to previously issued financial statements. ☐

Indicate by check mark whether any of those error corrections are restatements that required a recovery analysis of incentive-based compensation received by any of the registrant's executive officers during the relevant recovery period pursuant to § 240.10D-1(b). ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ☐ No ☒

The aggregate market value of the registrant's common shares held by non-affiliates computed by reference to the price at which the common equity was last sold on June 30, 2024, was approximately US$77.5 billion.

As at February 7, 2025, the registrant had 2,179,049,670 common shares outstanding.

DOCUMENTS INCORPORATED BY REFERENCE:
Not applicable.

EXPLANATORY NOTE

Enbridge Inc., a corporation existing under the *Canada Business Corporations Act*, qualifies as a foreign private issuer in the United States (US) for purposes of the *Securities Exchange Act of 1934, as amended* (the Exchange Act). Although, as a foreign private issuer, Enbridge Inc. is not required to do so, Enbridge Inc. currently files annual reports on Form 10-K, quarterly reports on Form 10-Q, and current reports on Form 8-K with the Securities and Exchange Commission (SEC) instead of filing the reporting forms available to foreign private issuers.

Enbridge Inc. intends to prepare and file a management information circular and related material under Canadian requirements. As Enbridge Inc.'s management information circular is not filed pursuant to Regulation 14A, Enbridge Inc. may not incorporate by reference information required by Part III of this Form 10-K from its management information circular. Accordingly, in reliance upon and as permitted by Instruction G(3) to Form 10-K, Enbridge Inc. will be filing an amendment to this Form 10-K containing the Part III information no later than 120 days after the end of the fiscal year covered by this Form 10-K.

GLOSSARY

"we", "our", "us" and "Enbridge"	Enbridge Inc.
AFUDC	Allowance for funds used during construction
Aitken Creek	Aitken Creek Gas Storage Facility
AOCI	Accumulated other comprehensive income/(loss)
ARO	Asset retirement obligations
ATM Program	The at-the-market equity issuance program
Aux Sable	US Midstream ownership interest in Aux Sable Liquid Products LP, Aux Sable Midstream LLC, Aux Sable Canada LP
BC	British Columbia
bcf/d	Billion cubic feet per day
CER	Canada Energy Regulator
DAPL	Dakota Access Pipeline
Dawn	An extensive network of underground storage pools at the Tecumseh Gas Storage facility and Dawn Hub
DCP	DCP Midstream, LP
EBITDA	Earnings before interest, income taxes and depreciation and amortization
EEP	Enbridge Energy Partners, L.P.
EIEC	Enbridge Ingleside Energy Center
EIS	Environmental Impact Statement
Enbridge Gas Ontario	Enbridge Gas Inc.
EOG	The East Ohio Gas Company
EPS	Emissions performance Standards
ESG	Environment, Social and Governance
Exchange Act	United States Securities Exchange Act of 1934
FERC	Federal Energy Regulatory Commission
GHG	Greenhouse gas
Gray Oak	Gray Oak Pipeline, LLC
IAA	The Impact Assessment Act by the Government of Canada
Idaho Commission	The Idaho Public Utilities Commission
ISO	Incentive Stock Options
kbpd	Thousand barrels per day
LMCI	Land Matters Consultation Initiative
LNG	Liquefied natural gas
M&N	Maritimes & Northeast Pipeline
M&N Canada	Canadian portion of our Maritimes & Northeast Pipeline
MPLX	MPLX LP
MTS	Mainline Tolling Settlement
MW	Megawatts
NEXUS	NEXUS Gas Transmission, LLC
NGL	Natural gas liquids
North Carolina Commission	The North Carolina Utilities Commission
NRGreen	NRGreen Power Limited Partnership

OCI	Other comprehensive income/(loss)
OEB	Ontario Energy Board
Ohio Commission	The Public Utilities Commission of Ohio
OPEB	Other postretirement benefit obligations
Phase 1 Decision	The Ontario Energy Board's Decision and Order on December 21, 2023, on Phase 1 of Enbridge Gas Inc.'s application to establish a 2024 through 2028 Incentive Regulation rate setting framework
PIR	Pipeline Infrastructure Replacement
PPA	Power purchase agreements
PSNC	Public Service Company of North Carolina, Incorporated
PSU	Performance Stock Units
Questar	Questar Gas Company
RNG	Renewable natural gas
ROE	Return on Equity
ROU	Right-of-use
RSU	Restricted Stock Units
SEC	US Securities and Exchange Commission
SEP	Spectra Energy Partners, LP
Spectra Energy	Spectra Energy Corp
Texas Eastern	Texas Eastern Transmission, LP
TGE	Tri Global Energy, LLC
the Acquisitions	Enbridge Inc.'s acquisitions of three US gas utilities from Dominion Energy, Inc.
the Band	Bad River Band of the Lake Superior Tribe of Chippewa Indians
the Board	Board of Directors
the Court	The US District Court for the Western District of Wisconsin
the EOG Acquisition	Enbridge Inc.'s acquisition of all of the outstanding shares of capital stock of The East Ohio Gas Company on March 6, 2024
the Partnerships	Spectra Energy Partners, LP and Enbridge Energy Partners, L.P.
the PSNC Acquisition	Enbridge Inc.'s acquisition of all of the membership interests of Fall North Carolina Holdco LLC, which owns 100% of Public Service Company of North Carolina, Incorporated on September 30, 2024
the Questar Acquisition	Enbridge Inc.'s acquisition of all of the membership interests of Fall West Holdco LLC which owns 100% of Questar Gas Company and its related Wexpro companies on May 31, 2024
the Reservation	The Bad River Reservation
the Whistler Parent JV	The joint venture formed by Enbridge Inc., WhiteWater/I Squared Capital and MPLX LP on May 29, 2024
Tomorrow RNG	Six Morrow Renewables operating landfill gas-to-renewable natural gas production facilities
Tres Palacios	Tres Palacios Holdings LLC
UK	The United Kingdom
US	United States of America
US District Court	US District Court in the Western District of Michigan
US GAAP	Generally accepted accounting principles in the United States of America
Utah Commission	The Utah Public Service Commission

Vector	Vector Pipeline L.P.
VIEs	Variable interest entities
Wexpro	Wexpro Company and its consolidated subsidiaries
Wyoming Commission	The Wyoming Public Service Commission

CONVENTIONS

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

Unless otherwise specified, all dollar amounts are expressed in Canadian dollars, all references to "dollars" or "$" are to Canadian dollars and all references to "US$" are to US dollars. All amounts are provided on a before-tax basis, unless otherwise stated.

FORWARD-LOOKING INFORMATION

Forward-looking information, or forward-looking statements, have been included in this Annual Report on Form 10-K 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) 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 acquisition of three US gas utilities (US Gas Utilities) from Dominion Energy, Inc. (the Acquisitions); 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; expected closing of acquisitions, dispositions and other transactions and the timing thereof; expected benefits of transactions, including the Acquisitions; our ability to successfully integrate the US Gas Utilities; expected future actions of regulators and courts, government trade policies, including potential impacts of tariffs, duties, fees, economic sanctions, or other trade measures, and the timing and impact 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 assumptions about 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; 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 and interest rates 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); 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; political decisions; and evolving government trade policies, including potential and announced tariffs, duties, fees, economic sanctions, or other trade measures, global geopolitical 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 Annual Report on Form 10-K 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, Enbridge assumes no obligation to publicly update or revise any forward-looking statement made in this Annual Report on Form 10-K 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

Part II. Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations *(MD&A) in this Annual Report on Form 10-K 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 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.

PART I

ITEM 1. BUSINESS

Enbridge is a leading North American energy infrastructure company. Our core businesses include Liquids Pipelines, which consists of pipelines and terminals in Canada and the US that transport and export various grades of crude oil and other liquid hydrocarbons; Gas Transmission, which consists of investments in natural gas pipelines and gathering and processing facilities in Canada and the US; Gas Distribution and Storage, which consists of natural gas utility operations that serve residential, commercial and industrial customers in Canada and the US; and Renewable Power Generation, which consists primarily of investments in wind and solar assets, as well as geothermal and power transmission assets, in North America and Europe.

Enbridge is a public company, with common shares that trade on the Toronto Stock Exchange (TSX) and New York Stock Exchange (NYSE) under the symbol ENB. We were incorporated on April 13, 1970 under the Companies Ordinance of the Northwest Territories and were continued under the *Canada Business Corporations Act* on December 15, 1987.

A more detailed description of each of our businesses and underlying assets is provided below under *Business Segments*.

CORPORATE VISION AND STRATEGY

VISION

Enbridge through its diversified businesses, fuels people's quality of life in a safe and socially responsible manner in North America and beyond. Our vision is to provide energy in a planet-friendly way, everywhere people need it. In pursuing this vision, we seek to play a critical role in enabling the economic and social well-being of society by providing access to affordable, reliable, and secure energy through our infrastructure which transports, distributes, and generates energy, including liquids, natural gas, renewable power, and low-carbon fuels. We recognize that the energy system is changing, and we aim to provide a bridge to a cleaner energy future in a socially-responsible way, including selectively investing in lower-carbon energy technologies.

We aim to be a first-choice investment, supported by our investor value proposition of predictable and stable cash flows, a strong investment grade balance sheet to facilitate growth, a history of dividend increases, and a diversified opportunity set of growth projects in multiple jurisdictions to support continued EBITDA and distributable cash flow per share growth. Our assets are underpinned by long-term contracts, regulated cost-of-service tolling frameworks, power purchase agreements (PPAs), and other low-risk commercial arrangements.

We strive to be the leading first-choice energy delivery company in North America and beyond—for customers, communities, investors, regulators, policymakers, and employees. We approach this goal with a focus on worker and public safety, stakeholder relations, customer service, community investment, sustainability leadership, and employee engagement and satisfaction. As part of our community engagement, we remain committed to meaningful dialogue with Indigenous peoples to achieve common goals and constructive outcomes from our projects and operations. We also are committed to advancing investment opportunities with Indigenous groups, as demonstrated by recent partnerships on our oil pipelines and in the development of renewable energy projects.

STRATEGY

Our strategy is underpinned by a deep understanding of both local and global energy supply and demand fundamentals. Through disciplined capital allocation, aligned with our outlook on energy markets, we have become an industry leader with a diversified portfolio of infrastructure super systems across the North American continent, creating a platform for incremental growth. Our robust pipeline of project development opportunities, the integration of recent strategic acquisitions, and ongoing efficiency improvements are expected to drive our business forward. We remain confident in our balanced growth strategy and expect to continue to invest in our diversified footprint of both conventional businesses and complementary lower-carbon platforms. This includes extension and expansion opportunities to meet LNG exports and offshore gas, as well as leveraging North American electrification trends, including the expansion of data centers, where we can provide integrated customer solutions through our natural gas and renewable power businesses. Additionally, we are committed to effectively managing our emissions from our operations and building lasting and inclusive relationships with our stakeholders, including Indigenous peoples, our customers and employees.

Our assets have reliably generated low-risk, resilient cash flows through many different commodity, economic, and geopolitical environments. We believe that our asset quality, diversity, and ability to provide comprehensive solutions to customers which leverages expertise across our four business lines are key differentiators that enable us to be flexible in an uncertain business environment.

In order to continue to be an industry leader and to create value over the short and long term, we maintain a robust strategic planning process. We regularly conduct scenario and resiliency analysis on both our assets and business strategy. We test various value enhancement and maximization options, and we regularly engage with our Board of Directors (the Board) to promote alignment and maintain active oversight. This Board participation includes updates and discussions throughout the year and a dedicated annual strategic planning session. Going forward, we will continue to use this comprehensive approach to guide our investment decisions.

Consistent with our strategy, we have progressed several of our priorities in 2024. For example:

- We completed the acquisition of the US Gas Utilities with operations in Idaho, North Carolina, Ohio, Utah and Wyoming, creating the largest natural gas utility franchise in North America, providing visible, low-risk, long-term, rate base growth.

- Our Liquids Pipelines business exported record volumes through our Enbridge Ingleside Energy Center (EIEC), received approval from the Canada Energy Regulator (CER) in 2024 for our Mainline Tolling negotiated settlement through to 2028, sanctioned an expansion of the Gray Oak pipeline and incremental capacity at the EIEC following successful open seasons, and acquired marine docks with land adjacent to EIEC, further advancing our Permian export strategy.

- Our Gas Transmission business reached a negotiated settlement with shippers on Texas Eastern, announced and closed the Whistler Parent JV, a joint venture formed by Enbridge, WhiteWater/I Squared Capital and MPLX LP, connecting Permian Basin natural gas supply to growing LNG and other US Gulf Coast demand, and achieved final investment decision on the Tennessee Ridgeline Expansion and Blackcomb Natural Gas Pipeline. We also expanded our footprint in the Gulf Coast by sanctioning the Canyon System Pipelines and the formation of a joint venture to service the Sparta offshore development to serve BP, Shell and Equinor Gulf Coast developments. We also expanded our exposure to LNG by sanctioning the Venice Extension Project, which supplies the Venture Global Plaquemines LNG facility. We continue to work with customers on opportunities to supply new gas-fired power generation relating to data centers and growth of electricity demand generally, and capitalize on strong gas fundamentals to deliver safe, reliable, and lower-carbon energy to North Americans while simultaneously growing LNG exports.

- Our Gas Distribution and Storage business continued to advance its incentive regulation rate application in Ontario by filing a settlement proposal for the second phase of our 2024 rebasing application with the Ontario Energy Board (OEB), added approximately 36,000 new customers across our Ontario utilities business, commenced the integration of the Acquisitions, including its three million customers, and capitalized on increasing electric power and industrial demand - for example, by contracting gas supply to provide 200 megawatts (MW) of data center power in Utah and building the Moriah Energy Center, a 2 billion cubic feet LNG facility, to enable system growth and maintain reliability in North Carolina. We remain committed to assessing low-risk, capital investment opportunities, and providing cost-effective, reliable and lower-carbon energy to customers in Ontario, Quebec, Ohio, North Carolina, Utah, Wyoming, and Idaho.

- Our Renewable Power Generation business continued to execute on growth opportunities, including through our onshore business with the sanctioning of Orange Grove Solar in Texas (backed by a PPA with AT&T), Sequoia Solar in Texas (backed by a PPA with AT&T and Toyota), completion of Fox Squirrel Solar Phase 2 and 3 in Ohio (backed by a PPA with Amazon), and the announcement of the Seven Stars Energy Project, our first renewable power indigenous partnership focused on wind energy generation in Saskatchewan. We also continued to progress opportunities in our Offshore Wind business in Europe, including placing the Fécamp project into service, delivering first power to the French grid from the Provence Grand Large floating offshore wind project and more recently, winning an offshore wind farm tender for a project in the Mediterranean Sea off the southern coast of France.

- We continued to make meaningful progress towards our ESG goals. We further strengthened our relationships with Indigenous communities across North America while advancing our reconciliation commitments as a part of our Indigenous Reconciliation Action Plan, meeting 12 of 22 commitments. We are striving to reduce emissions from our operations through multiple pathways, including system modernization, and continued investment in our lower-carbon businesses.

- We continue to recycle capital at attractive valuations; in 2024, this included completing the sale of our interests in the Alliance Pipeline and Aux Sable facility. We remain focused on disciplined capital allocation, portfolio optimization and diversification, the continued enhancement of our industry leading cash flow profile and financial strength and flexibility. In addition, we continue to prioritize operating cost reductions across our business to increase our competitiveness and profitability.

These achievements are discussed in further detail in Part II. *Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations.*

Looking ahead, our near-term strategic priorities remain similar to past years. As always, proactively advancing the safety of our assets, protecting the environment, and maintaining system reliability remain our top priorities. We are focused on enhancing the value of our existing assets through further optimization, capitalizing on our extensive infrastructure to meet evolving customer needs, prioritizing in-franchise organic growth and export-driven opportunities, and continuing to develop lower-carbon platforms across all our businesses.

As an example, we are continuing to pursue opportunities related to electrification in North America, where we can utilize our existing gas transmission and distribution infrastructure to safely deliver gas to new and existing power plants being developed, given surging power demand. We are also pursuing opportunities to build new natural gas infrastructure along our network and within our gas distribution territories, combined with providing gas supply and storage to customers, to support this growth. To complement our natural gas offerings, we are also able to provide renewable energy solutions (electricity and renewable credits/offsets) to customers, which we view as a strategic competitive advantage, enabling us to expand our customer base and further extend our growth.

We expect to continue to invest on an attractive, risk-adjusted basis to advance our strategy and build a sustainable competitive advantage.

Our key strategic priorities include:

Safety and Operational Reliability
Safety and operational reliability are the foundation of our strategy. We strive to achieve and maintain industry leadership in all facets of safety - process, public, and personal - and ensure the highest standards of reliability and integrity across our system to protect our communities and the environment.

Extend Growth
The cornerstone of our growth lies in the successful execution of our slate of secured projects (currently $26 billion through 2029) on schedule and within estimated costs, while maintaining standards for safety, quality, customer satisfaction, and environmental and regulatory compliance. For a discussion of our current portfolio of capital projects refer to Part II. *Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - Growth Projects - Commercially Secured Projects*.

We continue to seek additional high-quality growth opportunities across all our platforms, and deploy capital towards optimal uses, prioritizing balance sheet strength, investment in low capital intensity growth, and regulated utility or utility-like projects. Our scale and diversification drive competitive advantages across the enterprise and generate opportunities for collaboration across the business units. The four business segments we operate share commercial advantages and strong stakeholder relationships that enable opportunities to cross-sell to customers across the business units, providing additional value and the potential for future growth. We will carefully assess our remaining investable capacity, deploying capital to the most value-enhancing opportunities available to us, including further organic growth, and complementary accretive "tuck-in" acquisitions that improve our competitive positioning or further strengthen our balance sheet.

Looking ahead, we see strong utilization of our network and opportunities for growth within each of our businesses. For example, we expect that:

- Our liquids pipelines infrastructure will remain a vital connection between key supply basins and demand-pull markets such as the refinery hubs in the US Midwest, eastern Canada, and the US Gulf Coast. We are advancing discussions with customers for additional Western Canadian Sedimentary Basin pipeline capacity in 2026 and beyond. We will continue to explore capital efficient growth opportunities via system expansions and optimization of operations. Our export infrastructure will also enable the transportation of crude oil, cleaner fuels, and other export opportunities. Building on our early experience, we expect that carbon capture and storage (CCS) offers the potential to provide additional new growth opportunities within our footprint in jurisdictions with supportive regulatory regimes.

- Our natural gas transmission business will seek extension and expansion opportunities driven by new load demand from gas-fired power generation (including for data centers, electrification, and reshoring), industrial growth, and coastal LNG plants. The strategic asset position we possess produces opportunities to accelerate growth and meet customer needs. Our rate regulated cost-of-service business model creates secured growth opportunities that yield predictable, low-risk cash flows. We are also focused on facilitating the connection of new gas supply to key demand centers and the build-out of our Permian gas value chain. Looking forward, we expect the integration of producing and blending RNG into our system to enhance asset longevity, enable us to offer differentiated lower-carbon solutions to customers and further decarbonize our gas offerings.

- Our North American gas distribution and storage business will continue to grow through customer additions and modernization investments. Data center driven demand presents an opportunity for the business to expand services by fueling natural gas power plants. We believe system and storage enhancements in the business will increase system flexibility, reliability, and price stability for customers.

- Our renewable power business continues to be well positioned to capitalize on the growth of renewables in North America and Europe through disciplined investment in diversified renewable technologies and selective development in supportive jurisdictions where we have an established presence. We will continue to leverage our strong internal capabilities and our existing partnerships to successfully execute our large development portfolio.

In addition, we aim to drive growth with a focus on optimization, modernization, productivity, and efficiency across all our businesses. Examples include: the application of drag-reducing agents and pump station modifications to optimize throughput on our liquids system, the execution of toll settlements and rate case filings to optimize revenue within our liquids pipeline and gas transmission franchises, the expansion of lower-carbon gas offerings to modernize and integrate value chains at our gas utilities, and the creation of sustainable cost savings across the organization through innovation, process improvement and system enhancements.

Maintain Financial Strength and Flexibility

Our financing strategies are designed to retain strong, investment-grade credit ratings so that we have the financial capacity to meet our capital funding needs and the flexibility to manage capital market disruptions. We expect that the current secured capital program can be readily financed through an equity self-funded model. For further discussion on our financing strategies, refer to Part II. *Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - Liquidity and Capital Resources*.

Disciplined Capital Allocation
We assess the latest fundamental trends, monitor the business landscape, and proactively conduct business development activities with the goal of identifying an industry-leading capital deployment opportunity set. We screen, analyze, and assess these opportunities using a disciplined investment framework with the objective of effectively deploying capital to grow while achieving attractive risk-adjusted returns, within our low-risk "utility-like" business model.

All investment opportunities are evaluated based on their potential to advance our strategy, mitigate risks, support our ESG goals, and create additional financial flexibility. Our primary emphasis in the near term is on low capital intensity opportunities to enhance returns across existing businesses (organic expansions and optimizations), system modernization, and utility rate-based investments. We also continue to assess other strong value-enhancing opportunities, including accretive acquisitions that can complement our portfolio.

In evaluating typical investment opportunities, we also consider other potential capital allocation alternatives. Other alternatives for capital deployment depend on our current outlook and include further debt reduction, dividend increases, and share buy-backs.

Participate in Energy Transition Over Time
As the global population grows and standards of living continue to improve around the world, we expect energy demand to rise. We, and our society, increasingly recognize the need for secure and reliable energy while concurrently reducing global greenhouse gas (GHG) emissions. Accordingly, energy systems around the world are being gradually reshaped as industry participants, regulators, and consumers seek to balance these factors. As a diversified energy infrastructure company, we believe that we are well positioned to play a role in the energy transition by lowering the emissions-intensity of the conventional fuels we transport and store, supporting the switching from higher emission energy sources to lower-carbon options for our customers, and selectively developing and constructing future lower-carbon energy infrastructure.

We believe that diversification and innovation will play a significant role in the energy transition. To date, we have made significant investments in natural gas infrastructure, emissions reduction technologies, and renewable energy assets, helping to decrease our emissions and further expand our platforms to support the global energy transition. Our focus areas in renewable energy remain in utility-scale onshore solar and wind projects, and integrated clean-energy offerings and solutions for customers. We are also participating in the development of other lower-carbon platforms like RNG, blue ammonia, CCS, and hydrogen gas (H2) where we can leverage our infrastructure, capabilities, and stakeholder relationships to accelerate growth and extend the value of our existing assets. Additionally, potential new investments are evaluated to assess their alignment with our GHG emissions reduction goals.

We work closely with our customers and stakeholders to maintain a pulse on the pace of the energy transition and are actively leveraging our execution capabilities and sustainability leadership to advance our positioning as a differentiated energy provider. We regularly test our assets under various transition scenarios to assess the resiliency of our business.

STRATEGIC ENABLERS
To successfully execute on our strategy and build competitive advantage, we focus on maintaining leading-edge capabilities in sustainability, talent, technology, operations, development, and growth capabilities.

Sustainability and Environmental, Social and Governance
Sustainability is integral to our ability to deliver energy in a safe and reliable manner. How well we perform as a steward of our environment; as a safe operator of essential energy infrastructure; as an inclusive employer; and as a responsible corporate citizen is inextricably linked to our ability to achieve our strategic priorities and create long-term value for all our stakeholders.

In 2024, we published our 23rd annual Sustainability Report outlining our progress against our ESG goals[1]. In particular, we:

- achieved our goal to reduce the emissions intensity of our operations (Scope 1 and Scope 2) from our 2018 base level through modernization and innovation of our system, front of the meter renewables, and execution of additional renewable power PPAs;
- surpassed both of our Board composition goals, progressed our efforts to strengthen inclusion in our workforce to enhance our business, and empowered our workforce through employee resource groups[1];
- made progress towards our Indigenous Reconciliation Action plan, including meeting 12 of 22 commitments; and
- continued to drive improvements towards our goal of zero safety incidents and injuries and progressed implementation of robust cyber defense programs.

Since setting our ESG goals in 2020, we have made considerable progress integrating sustainability into our strategy, governance, operations, and decision-making. We have linked sustainability performance to incentive compensation and are making meaningful progress towards these goals by executing on our action plans.

We are undertaking the following additional actions in support of our ESG goals:

- proactively working with organizations that are advancing emissions measurement and reduction guidelines for the midstream sector;
- collaborating with key suppliers on emissions reduction plans;
- further developing lower-carbon energy partnerships to drive innovation across our businesses, with a focus on renewable power, RNG, H2 and CCS; and
- continuing to advance our commitment to meaningful reconciliation and to building respectful and collaborative Indigenous partnerships.

We provide annual progress updates in our annual Sustainability Report which can be found at https://www.enbridge.com/sustainability-reports. ***Unless otherwise specifically stated, none of the information contained on, or connected to, the Enbridge website, including our annual Sustainability Report, is incorporated by reference in, or otherwise part of, this Annual Report on Form 10-K***.

Operations & Development

As a major infrastructure developer and operator, Enbridge focuses on excellence in our business, specifically in safety, regulatory, project execution, and efficiency. Safety is foundational at Enbridge and our safety-first mindset reflects our commitment to protecting the public, our workers, the environment, and the health of our pipelines and facilities. We recognize the importance of having strong trusted relationships with our regulators as we plan and execute projects and sustain ongoing operations. We are committed to being proactive on regulatory matters at the federal, regional, and local levels to develop and maintain a safe and reliable energy system that our customers and the public can count on.

Robust project development, execution, governance, stakeholder relations, and supply chain processes are also key to delivering projects on time, at high quality, and within estimated costs. We continually seek ways to improve our organizational efficiency and effectiveness across all our core functions, including by streamlining structures, simplifying processes, improving accountability, and effectively managing risk to drive top-tier performance.

[1] *All percentages or specific goals regarding ESG are aspirational goals which we intend to achieve in a manner compliant with state, local, provincial and federal law, including, but not limited to, executive orders, US federal regulations, the Equal Employment Opportunity Commission, and the Department of Labor.*

Talent
Our workforce is essential to our success and our focus remains on enhancing the capabilities and skills of our people. We are evolving our talent strategy enhancing our employee experience, and elevating our focus on learning and development. We value diversity of thought, and the focus on our approach to people leadership drives business performance. Furthermore, we strive to maintain industry-competitive compensation, flexibility, and retention programs that provide both short- and long-term performance incentives. We prioritize inclusion, along with our other business strategies because it is fundamentally important to our values and culture.

Technology
We recognize the vital role technology plays in helping us achieve our strategic objectives. We are committed to pursuing innovation and technology solutions that further our safety and reliability, maximize revenues, reduce costs, and enable transition to new, cleaner energy solutions. We continue to focus on resilience and reliability of our systems from a cybersecurity perspective and work to enhance our capabilities and educate our workforce to protect our critical infrastructure system from increasing threats. We also announced a collaboration with Microsoft leveraging artificial intelligence (AI) to drive advancements in safety, emissions reductions, and asset optimization.

Growth Capabilities
To achieve our vision and mission, we emphasize specific capabilities that will help us grow and build competitive advantage within our core and potential new businesses. We are increasing our focus on our customers so that we are responsive to their needs while also proactively helping them meet their decarbonization objectives. We are continuing to invest in leading corporate development capabilities to ensure we identify and execute on attractive capital recycling opportunities and acquisitions. Finally, we believe that the future energy system will not only continue to be highly integrated, but also become more complex. This will require an ecosystem of stakeholders to develop and manage from customers and lenders to equipment manufacturers and regulators. We believe it is critical to have strengths in partnership structuring and relationship management to build and maintain the robust energy infrastructure systems.

BUSINESS SEGMENTS

During 2024, our activities were carried out through four business segments: Liquids Pipelines, Gas Transmission, Gas Distribution and Storage, and Renewable Power Generation, as discussed below.

LIQUIDS PIPELINES

Liquids Pipelines consists of pipelines and terminals in Canada and the US that transport and export various grades of crude oil and other liquid hydrocarbons, which delivers approximately six million barrels per day (mmbpd) and is the largest global crude oil and liquids network.

MAINLINE SYSTEM

The Mainline System is a common carrier pipeline comprised of the Canadian Mainline and the Lakehead System. The Canadian Mainline transports various grades of crude oil and other liquid hydrocarbons within western Canada and from western Canada to the Canada/US border near Gretna, Manitoba and Neche, North Dakota and from the US/Canada border near Port Huron, Michigan and Sarnia, Ontario to eastern Canada. The Canadian Mainline includes six adjacent pipelines with a combined operating capacity of approximately 3.2 mmbpd that connect with the Lakehead System at the Canada/US border, as well as five pipelines that deliver crude oil and refined products into eastern Canada. Through our predecessors, we have operated, and frequently expanded, the Canadian Mainline since 1949. The Lakehead System is the portion of the Mainline System in the US. It is an interstate common carrier pipeline system regulated by the Federal Energy Regulatory Commission (FERC) and is the primary transporter of crude oil and liquid hydrocarbons from western Canada to the US.

Tolling Framework

The Mainline Tolling Settlement (MTS) is a negotiated settlement with a term of seven and a half years through the end of 2028 that covers both the Canadian and US portions of the Mainline, except for Lines 8 and 9 which are tolled on a separate basis. Enbridge filed an application with the CER for approval of the MTS on December 15, 2023 and the CER issued an order on March 4, 2024 approving Enbridge’s application as filed. The MTS provides for a Canadian Local Toll for deliveries within western Canada, as well as an International Joint Tariff (IJT) for crude oil shipments originating in western Canada, on the Canadian Mainline, and delivered into the US, via the Lakehead System, and into eastern Canada. Under the MTS, the Mainline operates as a common carrier system available to all shippers on a monthly nomination basis.

The MTS includes:

- an IJT, for heavy crude oil movements from Hardisty to Chicago, comprised of an initial Canadian Mainline Toll of $1.65 per barrel plus an initial Lakehead System Toll of US$2.57 per barrel, plus the applicable Line 3 Replacement surcharge;
- toll escalation for operation, administration, and power costs tied to US consumer price and US and Canadian power indices;
- tolls that are distance and commodity adjusted, and utilize a dual currency IJT; and
- a financial performance collar that provides incentives for Enbridge to optimize throughput and cost, but also provides downside protection in the event of extreme supply or demand disruptions or unforeseen operating cost exposure. This performance collar is intended to ensure the Mainline earns 11% to 14.5% returns, on a deemed 50% equity capitalization.

Approximately 70% of Mainline deliveries are tolled under this settlement, while approximately 30% of deliveries are tolled on a full path basis to markets downstream of the Mainline.

Lakehead System Local Tolls

Transportation rates are governed by the FERC for deliveries from the Canada/US border near Neche, North Dakota, Clearbrook, Minnesota and other points to principal delivery points on the Lakehead System. The Lakehead System periodically adjusts these transportation rates as allowed under the FERC’s index methodology and tariff agreements, the main components of which are index rates and the Facilities Surcharge Mechanism. Index rates, the base portion of the transportation rates for the Lakehead System, are subject to an annual inflationary adjustment which cannot exceed established ceiling rates as approved by the FERC. The Facilities Surcharge Mechanism allows the Lakehead System to recover costs associated with certain shipper-requested projects through an incremental surcharge in addition to the existing base rates and is subject to annual adjustment on April 1 of each year.

The Lakehead tolls are subject to an Offer of Settlement approved by the FERC on November 27, 2023 (Lakehead System Settlement). Lakehead System tolls were revised to reflect the terms of the Lakehead System Settlement effective December 1, 2023.

The Lakehead System Settlement includes:

- a resolution of litigation related to the index portion of the Lakehead System rate; and
- a depreciation truncation date of December 31, 2048 for the rate base applicable to the Index and Facilities Surcharge and agreement on the terms for future recovery through the Facilities Surcharge of costs related to two Line 5 projects: the Wisconsin Relocation Project and the Straits of Mackinac Tunnel.

REGIONAL OIL SANDS SYSTEM
The Regional Oil Sands System includes seven intra-Alberta long-haul pipelines: the Athabasca Pipeline, Waupisoo Pipeline, Woodland and Woodland Extension Pipelines, Wood Buffalo and Wood Buffalo Extension/Athabasca Twin pipeline system and the Norlite Pipeline System (Norlite), as well as two large terminals: the Athabasca Terminal located north of Fort McMurray, Alberta and the Cheecham Terminal, located south of Fort McMurray, Alberta. The Regional Oil Sands System also includes numerous laterals and related facilities which provide connectivity for several oil sands customers to the Edmonton and Hardisty areas.

The combined capacity of the intra-Alberta long-haul pipelines is approximately 1,120 thousand barrels per day (kbpd) to Edmonton and 1,415 kbpd into Hardisty, with Norlite providing approximately 218 kbpd of diluent capacity into the Fort McMurray region. We have a 50% interest in the Woodland Pipeline and a 70% interest in Norlite. The Regional Oil Sands System is anchored by long-term agreements with multiple oil sands producers that provide cash flow stability and also include provisions for the recovery of some of the operating costs of this system.

On October 5, 2022, we completed a transaction with Athabasca Indigenous Investments Limited Partnership (Aii), a newly created entity representing 23 First Nation and Metis communities, pursuant to which Aii acquired an 11.6% non-operating interest in the seven intra-Alberta long-haul pipelines in the Regional Oil Sands System.

GULF COAST AND MID-CONTINENT
Gulf Coast includes Flanagan South, Spearhead Pipeline, Seaway Crude Pipeline System (Seaway Pipeline), the Mid-Continent System (Cushing Terminal), Gray Oak, and the EIEC.

Flanagan South is a 950 kilometer (590 mile), 36-inch diameter interstate crude oil pipeline that originates at our terminal at Flanagan, Illinois, a delivery point on the Lakehead System, and terminates in Cushing, Oklahoma. Flanagan South has a capacity of approximately 700 kbpd.

Spearhead Pipeline is a long-haul pipeline that delivers crude oil from Flanagan, Illinois, a delivery point on the Lakehead System, to Cushing, Oklahoma. The Spearhead Pipeline has a capacity of approximately 193 kbpd.

We have a 50% interest in the 1,078 kilometer (670 mile) Seaway Pipeline, including the 805 kilometer (500 mile), 30-inch diameter long-haul system between Cushing, Oklahoma and Freeport, Texas, as well as the Texas City Terminal and Distribution System which serve refineries in the Houston and Texas City areas. Total aggregate capacity on the Seaway Pipeline system is approximately 950 kbpd. The Seaway Pipeline also includes 8.8 million barrels of crude oil storage tank capacity on the Texas Gulf Coast.

The Mid-Continent System is comprised of storage terminals at Cushing Terminal, consisting of over 110 individual storage tanks ranging in size from 78 to 570 thousand barrels. Total storage shell capacity of Cushing Terminal is approximately 26 million barrels. A portion of the storage facilities are used for operational purposes, while the remainder is contracted to various crude oil market participants for their term storage requirements. Contract fees include fixed monthly storage fees, throughput fees for receiving and delivering crude to and from connecting pipelines and terminals, and blending fees.

Gray Oak is a 1,368 kilometer (850 mile) crude oil system, transporting light crude oil, with origination points in the Eagle Ford and Permian Basins in West Texas. Gray Oak has delivery points at the US Gulf Coast and Houston refining region and currently has an average annual capacity of 900 kbpd; a planned expansion in 2025 will increase average annual capacity to 1,020 kbpd. Our effective economic interest in Gray Oak is 68.5% after our acquisition of Rattler Midstream's 10% interest in the pipeline in 2023. We assumed operatorship of Gray Oak in April 2023.

In October 2021, we acquired 100% of Moda Midstream Operating, LLC, which includes the EIEC, the largest crude oil export terminal by volume in North America. EIEC has an export capability of 1.6 million barrels per day. In 2024 we added a further 2 million barrels of storage at EIEC, bringing EIEC's total storage capability to 17.6 million barrels. We also own 100% interest in each of the 300-kbpd Viola pipeline, and the 350-thousand barrel Taft Terminal, both located near Corpus Christi, Texas. Additionally, in October 2024 we completed the acquisition of two marine docks and land adjacent to EIEC from Flint Hills Resources. This acquisition will add crude oil export capacity and streamline existing EIEC operations by increasing Very Large Crude Carrier windows on the primary facility docks. In November 2022, we acquired an additional 10% ownership interest in Cactus II Pipeline, a pipeline that travels from Wink to Ingleside within Texas, bringing our total non-operating ownership to 30%.

OTHER
Other includes Southern Lights Pipeline, Express-Platte System, Bakken System and Feeder Pipelines and Other.

The Southern Lights Pipeline is a single stream 180 kbpd 16/18/20-inch diameter pipeline that ships diluent from the Manhattan Terminal near Chicago, Illinois to three western Canadian delivery facilities, located at the Edmonton and Hardisty terminals in Alberta and the Kerrobert terminal in Saskatchewan. Both the Canadian portion and the US portions of the Southern Lights Pipeline receive tariff revenues under long-term contracts with committed shippers. The Southern Lights Pipeline capacity is 90% contracted with the remaining 10% of the capacity assigned for shippers to ship uncommitted volumes. A fully subscribed open season was completed in December 2023, which has ensured contract levels remain at 90% through mid-2030.

The Express-Platte System consists of the Express Pipeline and the Platte Pipeline, and crude oil storage of approximately 5.6 million barrels. It is an approximate 2,736 kilometer (1,700 mile) long crude oil transportation system, which begins at Hardisty, Alberta, and terminates at Wood River, Illinois. The 310 kbpd Express Pipeline carries crude oil to US refining markets in the Rocky Mountains area, including Montana, Wyoming, Colorado and Utah. The 145 to 164 kbpd Platte Pipeline, which interconnects with the Express Pipeline at Casper, Wyoming, transports crude oil predominantly from the Bakken shale and western Canada to refineries in the Midwest. The Express Pipeline capacity is typically committed under long-term take-or-pay contracts with shippers. A small portion of the Express Pipeline capacity and all of the Platte Pipeline capacity is used by uncommitted shippers who pay only for the pipeline capacity they actually use in a given month.

The Bakken System consists of the North Dakota System and the Bakken Pipeline System. The North Dakota System services the Bakken Basin in North Dakota and is comprised of a crude oil gathering and interstate pipeline transportation system. The gathering system provides delivery to Clearbrook, Minnesota for service on the Lakehead system or a variety of interconnecting pipelines. The interstate portion of the system has both US and Canadian components that extend from Berthold, North Dakota into Cromer, Manitoba.

Tariffs on the US portion of the North Dakota System are regulated by the FERC. The Canadian portion is categorized as a Group 2 pipeline, and as such, its tolls are regulated by the CER on a complaint basis.

We have an effective 27.6% interest in the Bakken Pipeline System, which connects the Bakken Basin in North Dakota to markets in eastern Petroleum Administration for Defense Districts (PADD) II and the US Gulf Coast. The Bakken Pipeline System consists of the Dakota Access Pipeline from the Bakken area in North Dakota to Patoka, Illinois, and the Energy Transfer Crude Oil Pipeline from Patoka, Illinois to Nederland, Texas. Current capacity is approximately 750 kbpd of crude oil with the potential to be expanded through additional pumping horsepower. The Bakken Pipeline System is anchored by long-term throughput commitments from a number of producers.

Feeder Pipelines and Other includes a number of liquids storage assets and pipeline systems in Canada and the US.

Key assets included in Feeder Pipelines and Other are the Hardisty Contract Terminal and Hardisty Storage Caverns located near Hardisty, Alberta, a key crude oil pipeline hub in western Canada and the Southern Access Extension (SAX) Pipeline which originates in Flanagan, Illinois and delivers to Patoka, Illinois. We have an effective 65% interest in the 300 kbpd SAX pipeline. The majority of the SAX Pipeline's capacity is commercially secured under long-term take-or-pay contracts with shippers.

Feeder Pipelines and Other also includes Patoka Storage, the Toledo pipeline system and the Norman Wells (NW) System. Patoka Storage is comprised of four storage tanks with 480 thousand barrels of shell capacity located in Patoka, Illinois. The 180 kbpd Toledo pipeline system connects with the Lakehead System and delivers to Ohio and Michigan. The 45 kbpd NW System transports crude oil from Norman Wells in the Northwest Territories to Zama, Alberta and has a cost-of-service rate structure based on established terms with shippers.

CRUDE OIL MARKETING

The Liquids Pipelines segment also includes the Crude Oil Marketing business in Canada and the US, which provides physical commodity marketing and logistical services to North American refiners, producers, and other customers. The business is primarily focused on servicing customers across the value chain and capturing value from quality, time, and location price differentials when opportunities arise. To execute these strategies, the Crude Oil Marketing business transports and stores on both Enbridge-owned and third-party assets using a combination of contracted pipeline, storage, railcar, and truck capacity agreements.

COMPETITION

Competition for our liquids pipelines network comes primarily from infrastructure or logistics alternatives (e.g., rail or trucking) that transport liquid hydrocarbons from production basins in which we operate to markets in Canada, the US and internationally. Competition from existing pipelines, such as the recently completed Trans Mountain Pipeline expansion, is based primarily on access to supply, end use markets, the cost of transportation, contract structure and the quality and reliability of service. Additionally, volatile crude price differentials and insufficient pipeline capacity on either our or competitors' pipelines can make transportation of crude oil by rail competitive, particularly to markets not currently served by pipelines.

We believe that our liquids pipelines systems will continue to provide competitive and attractive options to producers in the Western Canadian Sedimentary Basin (WCSB), North Dakota, and the Permian Basin, due to our market access, competitive tolls and flexibility through our multiple delivery and storage points. We also employ long-term agreements with shippers, which mitigates competition risk by ensuring consistent supply to our liquids pipelines network. We have a proven track record of successfully executing projects to meet the needs of our customers.

Earnings from our Crude Oil Marketing business are primarily generated from arbitrage opportunities which, by their nature, can be replicated by competitors. An increase in market participants entering into similar arbitrage strategies could have an impact on our earnings. Efforts to mitigate competition risk include diversification of the marketing business by transacting at the majority of major hubs in North America and establishing long-term relationships with clients and pipelines.

SUPPLY AND DEMAND

We have an established and successful history of being the largest transporter of crude oil to the US, the world's largest market for crude oil. We expect US demand for Canadian crude oil production will support the use of our infrastructure for the foreseeable future.

Under most base case forecasts, demand is expected to grow into the next decade, primarily driven by emerging economies in regions outside the Organization for Economic Cooperation and Development (OECD), such as India and broader Southeast Asia. In North America, demand growth for transportation fuels is expected to slow down over time due to vehicle fuel efficiency improvement and rising adoption of electric vehicles.

The Organization of Petroleum Exporting Countries is expected to continue to balance markets and manage prices with production quotas despite accelerated developments of offshore production in both Brazil and Guyana and continued growth from Canada and the US. In the US, growth will likely be driven by the Permian Basin, a large and cost competitive light crude oil resource base. In addition, heavy crude oil growth is expected from the WCSB as additional egress availability will likely support expansion of existing projects and some potential new greenfield facilities.

Our Mainline System was effectively fully utilized in 2024 delivering 3.1 mmbpd. Refinery demand in the upper Midwest PADD II market has been strong. On the US Gulf Coast, lower supply of heavy crude from Latin America and the Middle East continues to drive increased demand for Canadian heavy crude. Many of the refineries connected to the Mainline System are complex and competitive in the global context.

The anticipated combination of long-term demand growth in non-OECD nations, domestic demand contraction over time, and continued production growth in the Permian Basin and WCSB, highlights the importance of our strategic asset footprint and reinforces the need for additional export-oriented infrastructure. We believe that we are well positioned to meet these evolving supply and demand fundamentals through expansion of system capacity for incremental access to the US Gulf Coast, and through further development of our EIEC in Corpus Christi, including the full integration and optimization of the Flint Hills marine docks and land acquired in October 2024.

Opposition to fossil fuel development in conjunction with evolving consumer preferences and new technologies could underpin energy transition scenarios impacting long-term supply and demand of crude oil. We continue to closely monitor the evolution of all of these factors to be able to proactively adapt our business to help meet our customers' and society's energy needs.

These supply and demand dynamics are evolving, as the current political climate in Canada and the US continues to shift, including as a result of changes in governments and trade relations. We continue to monitor these developments together with their impact on our business.

GAS TRANSMISSION

Gas Transmission consists of our investments in natural gas pipelines and gathering and processing facilities in Canada and the US, including US Gas Transmission, Canadian Gas Transmission, US Midstream and Other assets.

US GAS TRANSMISSION

US Gas Transmission includes ownership interests in Texas Eastern Transmission, LP (Texas Eastern), Algonquin Gas Transmission, LLC (Algonquin), Maritimes & Northeast (M&N) (US and Canada), East Tennessee Natural Gas, LLC (East Tennessee), Gulfstream Natural Gas System, L.L.C. (Gulfstream), Sabal Trail Transmission, LLC (Sabal Trail), NEXUS Gas Transmission, LLC (NEXUS), Valley Crossing Pipeline, LLC (Valley Crossing), Southeast Supply Header, LLC (SESH), Vector Pipeline L.P. (Vector), Whistler Parent, LLC (Whistler Parent JV), Delaware Basin Residue, LLC (DBR) and certain other gas pipeline and storage assets. The US Gas Transmission business primarily provides transmission and storage of natural gas through interstate pipeline systems for customers in various regions of the northeastern, southern and midwestern US.

The Texas Eastern interstate natural gas transmission system extends from supply and demand centers in the Gulf Coast region of Texas and Louisiana to supply and demand centers in Ohio, Pennsylvania, New Jersey and New York. Texas Eastern's onshore system has a peak day capacity of 12.0 billion cubic feet per day (bcf/d) of natural gas on approximately 13,745 kilometers (8,541 miles) of pipeline and associated compressor stations. Texas Eastern is also connected to five affiliated storage facilities that are partially or wholly-owned by other entities within the US Gas Transmission business, including the Tres Palacios Holdings LLC (Tres Palacios) storage facility that we acquired on April 3, 2023.

The Algonquin interstate natural gas transmission system connects with Texas Eastern’s facilities in New Jersey and extends through New Jersey, New York, Connecticut, Rhode Island and Massachusetts where it connects to M&N US. The system has a peak day capacity of 3.1 bcf/d of natural gas on approximately 1,817 kilometers (1,129 miles) of pipeline with associated compressor stations.

M&N US has a peak day capacity of 0.8 bcf/d of natural gas on approximately 552 kilometers (343 miles) of mainline interstate natural gas transmission system, including associated compressor stations, which extends from northeastern Massachusetts to the border of Canada near Baileyville, Maine. M&N Canada has a peak day capacity of 0.5 bcf/d on approximately 885 kilometers (550 miles) of interprovincial natural gas transmission mainline system that extends from Goldboro, Nova Scotia to the US border near Baileyville, Maine. We have a 78% interest in M&N US and M&N Canada.

East Tennessee’s interstate natural gas transmission system has a peak day capacity of 1.9 bcf/d of natural gas, crosses Texas Eastern’s system at two locations in Tennessee and consists of two mainline systems totaling approximately 2,449 kilometers (1,522 miles) of pipeline in Tennessee, Georgia, North Carolina and Virginia, with associated compressor stations. East Tennessee has an LNG storage facility in Tennessee and also connects to the Saltville storage facilities in Virginia.

Valley Crossing is an approximately 285 kilometer (177 mile) intrastate natural gas transmission system, with associated compressor stations. The pipeline infrastructure is located in Texas and provides market access of up to 2.6 bcf/d of design capacity to the Comisión Federal de Electricidad, Mexico’s state-owned utility.

Vector is an approximately 560 kilometer (348 mile) pipeline travelling between Joliet, Illinois in the Chicago area and Ontario. Vector can deliver 1.7 bcf/d of natural gas, of which 455 million cubic feet per day (mmcf/d) is leased to NEXUS. We have a 60% interest in Vector.

Gulfstream is an approximately 1,199 kilometer (745 mile) interstate natural gas transmission system with associated compressor stations. Gulfstream has a peak day capacity of 1.4 bcf/d of natural gas from Mississippi, Alabama, Louisiana and Texas, crossing the Gulf Coast to markets in central and southern Florida. We have a 50% interest in Gulfstream.

Sabal Trail is an approximately 832 kilometer (517 mile) interstate pipeline that provides firm natural gas transportation. Facilities include a pipeline, laterals and various compressor stations. The pipeline infrastructure is located in Alabama, Georgia and Florida, and adds approximately 1.0 bcf/d of capacity enabling the access of onshore gas supplies. We have a 50% interest in Sabal Trail.

NEXUS is an approximately 414 kilometer (257 mile) interstate natural gas transmission system with associated compressor stations. NEXUS transports natural gas from our Texas Eastern system in Ohio to our Vector interstate pipeline in Michigan, with peak day capacity of 1.4 bcf/d. Through its interconnect with Vector, NEXUS provides a connection to Dawn Hub, the largest integrated underground storage facility in Canada and one of the largest in North America, located in southwestern Ontario adjacent to the Greater Toronto Area. We have a 50% interest in NEXUS.

SESH is an approximately 462 kilometer (287 mile) interstate natural gas transmission system with associated compressor stations. SESH extends from the Perryville Hub in northeastern Louisiana where the shale gas production of eastern Texas, northern Louisiana and Arkansas, along with conventional production, is reached from six major interconnections. SESH extends to Alabama, interconnecting with 14 major north-south pipelines and three high-deliverability storage facilities and has a peak day capacity of 1.1 bcf/d of natural gas. We have a 50% interest in SESH.

The Whistler Parent JV holds a 100% interest in Whistler Pipeline, LLC (Whistler), a 450 mile intrastate pipeline with associated compressor stations that extends from the Permian Basin to Agua Dulce, Texas with a capacity of 2.5 bcf/d, a 70% interest in ADCC Pipeline, LLC (ADCC), a 40 mile pipeline that extends from Agua Dulce, Texas to Cheniere Energy's Corpus Christi LNG export facility with a capacity of 1.7 bcf/d, and a 50% interest in Waha Gas Storage, LLC, a 2.0 bcf gas storage cavern facility connecting to key Permian egress pipelines including Whistler. We have a 19% interest in the Whistler Parent JV.

DBR holds a 100% interest in Agua Blanca, LLC, Waha Connector, LLC, and Gateway Pipeline, LLC, a combined network of pipelines that connects Permian supply to Whistler and other pipelines transporting natural gas from the Permian Basin to downstream markets, and the remaining 50% interest in Waha Gas Storage, LLC not held by Whistler Parent JV. We have a 15% interest in DBR.

Transmission and storage services are generally provided under firm agreements where customers reserve capacity in pipelines and storage facilities. The vast majority of these agreements provide for fixed reservation charges that are paid monthly regardless of the actual volumes transported on the pipelines, plus a small variable component that is based on volumes transported, injected or withdrawn, which is intended to recover variable costs.

Interruptible transmission and storage services are also available where customers can use capacity if it exists at the time of the request and are generally at a higher toll than long-term contracted rates. Interruptible revenues depend on the amount of volumes transported or stored and the associated rates for this service. Storage operations also provide a variety of other value-added services including natural gas parking, loaning and balancing services to meet customers' needs.

CANADIAN GAS TRANSMISSION

Canadian Gas Transmission is comprised of Westcoast Energy Inc.'s (Westcoast) British Columbia (BC) Pipeline, and other minor midstream gas gathering pipelines. It also includes the Aitken Creek Gas Storage facility, located in BC, Canada, which we acquired on November 1, 2023.

The BC Pipeline provides natural gas transmission services, transporting processed natural gas from facilities located primarily in northeastern BC to markets in BC and the US Pacific Northwest. It has a peak day capacity of 3.6 bcf/d of natural gas on approximately 2,950 kilometers (1,833 miles) of transmission pipeline in BC and Alberta, as well as associated mainline compressor stations. BC Pipeline is regulated by the CER under cost-of-service regulation.

The majority of transportation services provided by Canadian Gas Transmission are under firm agreements, which provide for fixed reservation charges that are paid monthly regardless of actual volumes transported on the pipeline, plus a small variable component that is based on volumes transported to recover variable costs. Canadian Gas Transmission also provides interruptible transmission services where customers can use capacity if it is available at the time of request. Payments under these services are based on volumes transported.

US MIDSTREAM
US Midstream includes a 13.2% effective economic interest in DCP Midstream, LP (DCP). Prior to August 17, 2022, we had a 28.3% effective economic interest in DCP. DCP is a joint venture, with a diversified portfolio of assets, engaged in the business of gathering, compressing, treating, processing, transporting, storing and selling natural gas; producing, fractionating, transporting, storing and selling NGL; and recovering and selling condensate. DCP owns and operates more than 32 plants and approximately 86,016 kilometers (53,448 miles) of natural gas and NGL pipelines, with operations in nine states across major producing regions.

OTHER
Other consists primarily of our offshore assets. Enbridge Offshore Pipelines is comprised of 12 natural gas gathering and FERC regulated transmission pipelines and five oil pipelines. These pipelines are located in four major corridors in the Gulf Coast, extending to deepwater developments, and include almost 2,200 kilometers (1,365 miles) of underwater pipe and onshore facilities with total capacity of approximately 6.6 bcf/d.

In 2023, Enbridge acquired a 10% equity investment in Divert Inc., a RNG infrastructure company, which provides Enbridge with an option to invest up to $1.3 billion (US$1.0 billion) in food waste to RNG projects across the US.

On January 2, 2024, we acquired six Morrow Renewables operating landfill gas-to-RNG production facilities located in Texas and Arkansas. The acquired assets align with and advance our low-carbon strategy.

COMPETITION
Our natural gas transmission and storage businesses compete with similar facilities that serve our supply and market areas in the transmission and storage of natural gas. The principal elements of competition are location, rates, terms of service, flexibility and reliability of service.

The natural gas transported in our business competes with other forms of energy available to our customers and end-users, including electricity, coal, propane, fuel oils, nuclear and renewable energy. Factors that influence the demand for natural gas include price changes, the availability of natural gas and other forms of energy, levels of business activity, long-term economic conditions, conservation, legislation, governmental regulations, the ability to convert to alternative fuels, weather and other factors.

Competitors predominantly include interstate/interprovincial and intrastate/intraprovincial pipelines or their affiliates and other midstream businesses that transport, gather, treat, process and market natural gas or NGL. Because pipelines are generally the most efficient mode of transportation for natural gas over land, the most significant competitors of our natural gas pipelines are other pipeline companies.

SUPPLY AND DEMAND
Our gas transmission assets make up one of the largest natural gas transportation networks in North America, driving connectivity between prolific supply basins and major demand centers within the continent. Our systems have been integral to the transition in supply and demand markets over the last decade, and we expect to continue to play a part as the energy landscape evolves.

Natural gas production in the Appalachian and Permian Basins has grown dramatically in the past decade. Today, these regions produce more than 54 bcf/d of natural gas on a combined basis. Improved technology and increased shale gas drilling have increased the supply of low-cost natural gas. As well, there has been, and continues to be, a corresponding increase in demand for our natural gas infrastructure in North America. Through a series of expansions and reversals on our core systems, combined with the execution of greenfield projects and strategic acquisitions, we have been able to meet the needs of both producers and consumers. Our US Gas Transmission systems were initially designed to transport natural gas from the Gulf Coast to the supply-constrained northeast markets. Our asset base now has the capability to transport diverse bi-directional supply to the northeast, southeast, Midwest, Gulf Coast and LNG markets on a fully subscribed and highly utilized basis.

The northeast market continues its role as a predominantly supply constrained region with steady demand. The bi-directional capabilities offered by our US Gas Transmission system allow us to deliver in an efficient manner to our regional customers. The region has seen an increase in natural gas supply due to the development of the Marcellus and Utica shales in the Appalachia region.

The southeast market is linked to multiple, highly liquid supply pools that include the Marcellus and Utica shale developments, offering consistent supply and stable pricing to a growing population of end-use customers across our multiple systems under long-term, utility-like arrangements.

With connectivity to Appalachian and western Canadian supply through our Westcoast Pipeline, the Midwest market has access to two of the lowest cost gas producing regions on the continent. As demand in the region is expected to remain stable over the next decade, maintaining this link will remain important. Flexibility in supply for this market is especially critical to maintaining liquidity and price stability as natural gas continues to replace coal-fired generation.

Gulf Coast demand growth is being driven by an increase in the volume of LNG exports, an ongoing wave of gas-intensive petrochemical facilities and additional pipeline exports to Mexico. Demand in these markets in the region is anticipated to grow by approximately 20 bcf/d through 2040. The Gulf Coast market has been the beneficiary of low-cost capacity on our assets as the relationship between supply and market centers has shifted. Such cost-effective capacity is difficult to access or replicate, offering existing shippers and transporters stability of capacity and utilization. Tide-water market access and proximity to Mexico continue to make this region a platform of global trade as pipeline and LNG exports continue their growth trajectory. In 2024, the US exported over 12 bcf/d of natural gas to LNG markets, primarily from the Gulf Coast region.

Western Canada is also a source of low-cost supply seeking access to premium markets in North America and globally. One of the few vital links to demand centers in the Pacific Northwest is our BC Pipeline, which is highly utilized. The continental supply profile has shifted to natural gas shale plays such as the Montney and Duvernay within western Canada. These plays are expected to fulfill an integral role as Canada enters the global market as an LNG exporter. Western Canada's production is forecasted to increase from 18 bcf/d in 2024 to 23 bcf/d by 2040. This growth will support an additional 5 bcf/d of LNG exports. These supply shifts have shaped our growth strategies and affect the nature of the projects anticipated in the capital expenditures discussed below in Part II. *Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations - Growth Projects - Commercially Secured Projects.*

Global energy demand is expected to increase approximately 20% by 2050, according to the recently released 2024 International Energy Agency (IEA) report, driven primarily by economic growth in non-OECD countries. According to the IEA Stated Policy Scenario, natural gas will play an important role in meeting this energy demand, and gas consumption is anticipated to grow by approximately 16% during this period as one of the world's most significant energy sources. North American exports are expected to play a significant part in meeting global demand, underscoring the ability of our assets to remain highly utilized by shippers, and highlighting the need for incremental transportation solutions across North America, as well as for the further build-out of export facilities to meet international demand.

The long-term effects on global gas markets of the ongoing conflict in Ukraine remain uncertain. In 2022, Europe saw a sharp rise in natural gas prices due to a decrease in supply from Russia. Global LNG markets responded, and LNG cargoes were redirected from the Asian market to Europe which allowed Europe to meet peak demand during what turned out to be a mild winter. Natural gas storage volumes have been strong entering the 2024-2025 winter season in Europe, and mild winter temperatures have thus far helped to moderate prices. The outlook for gas prices remains somewhat volatile but is generally anticipated to see a gradual normalization as LNG export volumes are expected to ramp up in 2026-2027.

Europe continues to seek lower-carbon gas supplies and has accelerated plans to develop hydrogen as an alternative to natural gas. The global hydrogen market is still relatively immature, but with the introduction of new incentives, such as those in the *US Inflation Reduction Act* and the regulations enacted thereunder, hydrogen production at large scale is becoming increasingly commercialized, which has led to a growing export market. Given its proximity to low-cost natural gas supplies and suitable geologic storage for carbon dioxide, the US Gulf Coast is well positioned to be a leading export hub to supply blue hydrogen to international markets. Given these rapidly changing global fundamentals and coupled with growing appetite for lower-carbon hydrogen, we believe we are well positioned to provide value-added solutions to shippers and meet both regional and international demand.

Opposition to natural gas development, including new pipeline projects, exists in certain jurisdictions, which may challenge continued growth of the North American gas market and the ability to efficiently connect supply and demand. We are responding to the need for regional infrastructure with additional investments in Canadian and US gas transportation facilities. Progress on the development and construction of our commercially secured growth projects is discussed in Part II. *Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - Growth Projects - Commercially Secured Projects*.

RNG is seen as a more environmentally friendly alternative to traditional natural gas, as it is derived from organic waste sources such as agricultural residues, food waste, and other organic waste material. The production process most commonly involves the anaerobic digestion of these organic materials, resulting in the generation of biogas composed primarily of methane. Unlike conventional natural gas, RNG is considered carbon-neutral or even carbon-negative, as the carbon dioxide that is ultimately released during combustion is offset by the carbon captured during the organic matter's growth. This closed-loop cycle can contribute to mitigating GHG emissions and help to address climate change concerns. RNG can be seamlessly integrated into existing natural gas infrastructure, offering a versatile energy source for heating, transportation, and electricity generation. As societies increasingly prioritize reducing emissions, RNG has the potential to play an important role in the transition towards a cleaner and more resilient energy future. Global RNG consumption is expected to increase with a 11% compound annual growth rate until 2050, according to IEA's recently released Stated Policy Scenario.

These supply and demand dynamics are evolving, as the current political climate in Canada and the US continues to shift, including as a result of changes in governments. We continue to monitor these developments together with their impact on our business.

GAS DISTRIBUTION AND STORAGE

Gas Distribution and Storage consists of our rate-regulated natural gas utility operations, which serves residential, commercial and industrial customers in Ontario, Quebec, Ohio, North Carolina, Utah, Wyoming, and Idaho as well as Wexpro Company (Wexpro), which develops and produces natural gas reserves on behalf of Enbridge Gas Utah, Enbridge Gas Wyoming, and Enbridge Gas Idaho. Our distribution systems, which are supported by storage and compression assets, carry natural gas from the point of local supply to customers across North America.

There are three principal interrelated aspects of the natural gas distribution business in which our franchises are directly involved: Distribution, Transportation and Storage. The number of customers, and approximate combined length of pipelines for each of our major distribution and transmission systems as at December 31, 2024 are as follows:

As at December 31, 2024	Number of Customers (in millions)	Combined Length
Enbridge Gas Ontario	3.9	156,000 km (96,934 miles)
Enbridge Gas Ohio	1.2	35,406 km (22,000 miles)
Enbridge Gas Utah, Wyoming and Idaho	1.2	33,796 km (21,000 miles)
Enbridge Gas North Carolina	0.7	20,921 km (13,000 miles)

Our storage system principally consists of our assets at Dawn Hub and the Tecumseh Gas Storage facility.

Distribution

The principal source of revenue for Gas Distribution and Storage arises from the distribution of natural gas to customers. The services provided to residential, small commercial and industrial heating customers are primarily on a general service basis, without a specific fixed term or fixed price contract. The services provided to larger commercial and industrial customers are usually on an annual contract basis under firm or interruptible service contracts. Under a firm contract, we are obligated to deliver natural gas to the customer up to a maximum daily volume. The service provided under an interruptible contract is similar to that of a firm contract, except that it allows for service interruption at our option primarily to meet seasonal or peak demands. The respective regulator for each province or state approves rates for both contract and general services.

Customers have a choice with respect to natural gas supply. Customers may purchase and deliver their own natural gas to points upstream of the distribution system or directly into our distribution systems, or, alternatively, they may choose a system supply option, whereby customers purchase natural gas from our supply portfolio. A significant portion of our customers in Ohio participate in the Energy Choice program, under which residential customers are encouraged to purchase gas directly from retail suppliers or through a community aggregation program and have it delivered by us. Customers in our other franchise areas predominantly purchase gas from our diversified natural gas supply portfolio, which we maintain by acquiring supplies on a delivered basis, as well as acquiring supply from multiple supply basins across North America. Certain of our US Gas Utilities have a revenue decoupling mechanism whereby non-gas revenues are decoupled from the temperature-adjusted usage per customer, which allows for the collection of an allowed monthly revenue per customer and to promote energy conservation.

Transportation

Our gas utility franchises also offer transportation services to move gas through the areas we operate in to key markets throughout North America. Enbridge Gas Ontario contracts for firm transportation service, primarily with TransCanada Pipelines Limited, Vector and NEXUS, to meet its annual natural gas supply requirements. The transportation service contracts are not directly linked with any particular source of natural gas supply. Separating transportation contracts from natural gas supply provides flexibility in obtaining its own natural gas supply and accommodating the requests of its direct purchase customers for assignment of pipeline capacity.

In addition to contracting for transportation service, Enbridge Gas Ontario offers firm and interruptible transportation services on its own Dawn-Parkway pipeline system. Enbridge Gas Ontario's transmission system also links an extensive network of underground storage pools at the Tecumseh Gas Storage facility and Dawn Hub (collectively, Dawn) to major Canadian and US markets, and forms an important link in moving natural gas from western Canada and US supply basins to central Canadian and northeastern US markets.

As the supply of natural gas in areas close to Ontario has continued to grow, there has been increased demand to access these diverse supplies at Dawn and transport them along the Dawn-Parkway pipeline system to markets in Ontario, eastern Canada and the northeastern US. A substantial amount of Enbridge Gas Ontario's transportation revenue is generated by fixed annual demand charges.

Enbridge Gas Ohio system expansion projects over the last decade have provided the opportunity to offer transportation services as an attractive outlet for shale production, by virtue of its proximity to the Utica and Marcellus shale basins while enhancing on-system operational flexibility.

Storage

Our gas distribution business is highly seasonal as daily market demand for natural gas fluctuates with changes in weather, with peak consumption occurring in the winter months. Utilization of storage facilities permits us to take delivery of natural gas on favorable terms during off-peak summer periods for subsequent use during the winter heating season. This practice helps to minimize the annual cost of transportation of natural gas from its supply basins, assists in reducing our overall cost of natural gas supply and adds a measure of security in the event of any short-term interruption of transportation of natural gas to our franchise areas.

The storage facility at Dawn is located in southwestern Ontario and has a total working capacity of approximately 284 bcf in 33 underground facilities located in depleted gas fields. Dawn is the largest integrated underground storage facility in Canada and one of the largest in North America. Approximately 180 bcf of the total working capacity is available to Enbridge Gas Ontario for utility operations. There is approximately 60 bcf of underground storage in Ohio that provides additional flexibility for system reliability and managing the cost of supply for customers.

Dawn offers customers an important link in the movement of natural gas from western Canadian and US supply basins to markets in central Canada and the northeast US. Dawn's configuration provides flexibility for injections, withdrawals and cycling. Customers can purchase both firm and interruptible storage services at Dawn. Dawn offers customers a wide range of market choices and options with easy access to upstream and downstream markets. A substantial amount of Enbridge Gas Ontario's storage revenue is generated by fixed annual demand charges.

COMPETITION

Our gas distribution systems are regulated by the OEB, the Québec Régie de l'énergie, the Public Utilities Commission of Ohio (Ohio Commission), the North Carolina Utilities Commission (North Carolina Commission), the Utah Public Service Commission (Utah Commission), the Wyoming Public Service Commission (Wyoming Commission), and the Idaho Public Utilities Commission (Idaho Commission). Our gas distribution systems are not generally subject to third-party distribution competition within their franchise areas.

Our gas distribution business competes with other forms of energy available to customers and end-users, including electricity, coal, propane and fuel oils. Factors that influence the demand for natural gas include weather, price changes, the availability of natural gas and other forms of energy, the level of business activity, conservation, legislation, including the federal carbon pricing laws in Canada, governmental regulations, the ability to convert to alternative fuels, and other factors.

SUPPLY AND DEMAND

We anticipate that demand for natural gas in North America will stabilize over the long term with potential growth in peak day demands and from the data center build-out; however, there are risks to the natural gas market that may challenge its growth prospects.

Net-zero carbon policies, evolving customer preferences for lower-carbon fuels and more efficient technologies, combined with increasing opposition to natural gas development in certain parts of North America, may reduce the markets' ability to efficiently deploy capital to connect supply and demand. We monitor these factors closely in order to align our business strategy with shifts in customer preferences and public policy requirements.

Enbridge continues to focus on promoting conservation and energy efficiency by undertaking activities focused on reducing natural gas consumption through various demand side management programs offered across all markets and sourcing supply with a smaller carbon footprint. In addition to our existing and proposed RNG programs, we are also continuing our efforts to source other lower-carbon supplies, such as hydrogen.

Supply and demand are also impacted by the legislative environments in which our franchises operate. For example, in 2024, Ontario passed Bill 165, the *Keeping Energy Costs Down Act* which reset the revenue horizon to 40 years for residential and small volume consumers and streamlined the regulatory process for pipelines between $2-$10 million. Ontario further demonstrated its support for gas in its vision paper for integrated energy planning where it confirmed its view that "Gas is a vital component of Ontario's energy mix". House Bill 507 was signed in Ohio officially defining natural gas as a "green energy". Ohio and Utah both passed bills in 2021 (House Bill 201 and House Bill 17, respectively) prohibiting bans on natural gas. The law prohibits municipalities and counties from enacting "an ordinance, a resolution, or a policy that prohibits, or has the effect of prohibiting, the connection or reconnection of an energy utility service." However, it does not block local or county officials from supporting electrification through incentives or restricting gas use in municipal or county buildings. In 2021, House Bill 951 was signed in North Carolina, directing the North Carolina Commission to develop a plan, known as the NC Carbon Plan, for a 70% reduction in carbon emissions in the electricity sector by 2030 that is driving coal-to-gas generation switching.

Over the past decade, growth in the North American gas supply landscape, driven mainly by the development of unconventional gas resources in the Montney, Permian, Marcellus and Utica supply basins, has resulted in lower annual commodity prices and narrower seasonal price spreads. Natural gas prices have been impacted by lower weather-related demand and higher North American inventory levels resulting in more stable and lower prices. Unregulated storage values are primarily determined by the difference in value between winter and summer natural gas prices.

Enbridge Gas Utah, Enbridge Gas Wyoming and Enbridge Gas Idaho have a cost-of-service agreement with Wexpro, which develops and produces natural gas reserves on behalf of the utility. Wexpro's production supplies up to 55% of annual demand for the utility (up to 65% if certain conditions are met and approvals obtained) and provides a physical hedge against commodity price volatility while maintaining the option to purchase from third-party suppliers at market rates through long-term contracts. Wexpro's operations stretch from the northern tip of the Greater Green River Basin in Pinedale, Wyoming, through the Vermillion Basin of Wyoming and Colorado, down to the Uinta Basin of Utah. Wexpro establishes its annual drilling program by forecasting the utility's consumption needs.

Operating since December 2022, Magna LNG is a 1.2 bcf LNG facility located in Magna, Utah. The facility provides system reliability for Enbridge Gas Utah's customers in Salt Lake City and the surrounding counties. LNG is produced primarily during the warmer months of the year and then stored to be used when needed for reliability.

RENEWABLE POWER GENERATION

Renewable Power Generation consists primarily of investments in wind and solar assets, as well as equity interests in geothermal power and power transmission assets. In North America, assets are primarily located in the provinces of Alberta, Ontario and Québec, and in the states of Colorado, Texas, Indiana, Ohio and West Virginia. In Europe, we hold equity interests in operating offshore wind facilities in the coastal waters of the United Kingdom, France, and Germany, as well as interests in several offshore wind projects under construction and active development in France and the United Kingdom.

Combined Renewable Power Generation investments represent approximately 3,500 MW of net generation capacity, which primarily consists of approximately:

- 1,399 MW generated by North American wind facilities;
- 621 MW generated by European offshore wind facilities;
- 97 MW expected to be generated by the Calvados Offshore Wind Project in France, which is currently under construction; and
- 440 MW generated by North American solar facilities in operation, with an additional 945 MW in projects in pre-construction and under construction.

The vast majority of the power produced from these facilities is sold under long-term PPAs.

JOINT VENTURES / EQUITY INVESTMENTS
Most of our investments in Canadian wind and solar assets and two of our US renewable assets are held within a joint venture in which we manage and operate a 51% interest. One of our US solar projects is held within a separate joint venture in which we hold a 50% interest.

We also own interests in European offshore wind facilities through the following joint ventures:

- a 24.9% interest in Rampion Offshore Wind, located in the United Kingdom;
- a 49.9% interest in Hohe See and Albatros Offshore Wind, located in Germany;
- a 25.5% interest in the Saint-Nazaire Offshore Wind Project, located in France;
- a 25% interest in the Provence Grand Large Floating Offshore Wind Project, located in France;
- a 17.9% interest in the Fécamp Offshore Wind Project, located in France; and
- a 21.7% interest in the Calvados Offshore Wind Project, under construction in France.

COMPETITION
Renewable Power Generation operates in the North American and European power markets, which are subject to competition and supply and demand fundamentals for power in the jurisdictions in which it operates. The majority of our revenue is generated from long-term PPAs (or has been substantially hedged). As such, financial performance is not significantly impacted by fluctuating power prices arising from supply/demand imbalances or the actions of competing facilities during the term of the applicable contracts. However, the renewable energy sector includes large utilities, small independent power producers and private equity investors, which are expected to aggressively compete for new project development opportunities and for the right to supply customers when contracts expire.

To grow in an environment of heightened competition, we strategically target regions with commercial constructs consistent with our low risk business model. In addition, we leverage our expertise in developing and constructing large-scale infrastructure projects.

SUPPLY AND DEMAND
Renewable power generation in North America and Europe is expected to grow significantly over the next 20 years due to growing power demand and the replacement of retiring fossil fuel-based sources of electricity generation.

Strong load growth across North America is anticipated, driven by growing data center power demand and other large industrial load, as well as the continued electrification within the residential, transportation and industrial sectors. Furthermore, voluntary GHG emissions reduction targets are becoming increasingly expected by stakeholders, which is driving significant demand from corporate electricity end-users for cleaner electricity and environmental attributes.

In response to the growing demand outlook, North America requires significant new generation capacity from preferred technologies. Gas-fired and renewable energy facilities, including solar and wind (which make up the bulk of our renewable power assets), are generally the preferred sources to meet the increased load and replace coal-fired generation due to their lower-carbon intensities. Governments are also proposing tax incentives to support low-emission and renewable energy generation resource development. As renewable energy takes an increasing share of certain states' and provinces' electricity grids, governments are also proposing tax incentives for natural gas and battery development to help firm the variable generation on the grid.

Falling capital and operating costs of wind and solar, combined with their improving capacity factors, are expected to continue the ongoing trend of making renewable energy more competitive and support investment over the long-term, regardless of available government incentives. Generation from wind and solar sources is expected to more than triple over the next two decades in North America. Aside from the construction of new wind and solar facilities, other growth opportunities include repowering projects to increase output from and extend the project-life of our existing facilities.

In Europe, the renewable energy outlook is robust. Demand for electricity is expected to gradually increase over the next two decades, driven by electrification of transportation and buildings, and the desire to reduce reliance on gas sourced from Russia. Energy efficiency gains are expected to temper, but not eliminate, demand growth. Renewable power is expected to play a significant role in Europe's ability to meet its aggressive lower-carbon and renewable energy targets.

We, through our European joint ventures, continue to invest in offshore wind projects in the United Kingdom, France and Germany, and to explore opportunities to meet the growing demand.

ELIMINATIONS AND OTHER

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 subsidiaries. The principal activity of our captive insurance subsidiaries is providing insurance and reinsurance coverage for certain insurable property and casualty risk exposures of our operating subsidiaries and certain equity investments. Eliminations and Other also includes new business development activities and corporate investments, and natural gas and power marketing and logistical services to North American refiners, producers, and other customers.

REGULATION

GOVERNMENT REGULATION

Pipeline Regulation

Our Liquids Pipelines and Gas Transmission assets are subject to numerous operational rules and regulations mandated by governments and applicable regulatory authorities, breaches of which could result in fines, penalties, operating restrictions and an overall increase in operating and compliance costs.

In the US, our interstate pipeline operations are subject to pipeline safety laws and regulations administered by the Pipeline and Hazardous Materials Safety Administration (PHMSA), an agency within the US Department of Transportation (DOT). These laws and regulations require us to comply with a significant set of requirements for the design, construction, maintenance and operation of our interstate pipelines. These laws and regulations, among other things, include requirements to monitor and maintain the integrity of our pipelines and to operate them within permissible design limits such as pressures.

PHMSA continues to review existing regulations and establish new regulations to support safety and environmental standards that are designed to improve operations integrity management processes and reduce methane emissions. In this climate of increasingly stringent regulation, pipeline failure or failures to comply with applicable regulations could result in reduction of allowable operating pressures as authorized by PHMSA, which would reduce available capacity on our pipelines. Should any of these risks materialize, it may have an adverse effect on our operations, capital expenditures, earnings, cash flows, financial condition and competitive advantage.

Our ability to establish transportation and storage rates on our US interstate natural gas facilities is subject to regulation by the FERC, whose rulings and policies could have an adverse impact on the ability to recover the full cost of operating these pipeline and storage assets, including a reasonable rate of return. Regulatory or administrative actions by the FERC such as rate proceedings, applications to certify construction of new facilities, and depreciation and amortization policies, can affect our business, including decreasing tariff rates and revenues and increasing our costs of doing business.

In Canada, our pipelines are subject to safety regulations administered by the CER or provincial regulators. Applicable legislation and regulations require us to comply with a significant set of requirements for the design, construction, maintenance and operation of our pipelines. Among other obligations, this regulatory framework imposes requirements to monitor and maintain the integrity of our pipelines.

As in the US, laws and regulations addressing enhanced pipeline safety in Canada have been enacted over the past few years and are continuously being monitored. These changes demonstrate an increased focus on the implementation of management systems to address key areas, such as emergency management, integrity management, safety, security and environmental protection. The CER has authority to impose administrative monetary penalties for non-compliance with the regulatory regime it administers, as well as to impose financial requirements for future abandonment and major pipeline releases.

A key component of pipeline safety and reliability is the approach to integrity management that uses reliability targets and safety case assessments. A long history of extensive inline inspection has provided detailed knowledge of the assets in our pipeline systems. Our pipelines are assessed and maintained in a proactive manner in order to meet reliability targets. Furthermore, the integrity management program has an independent step to check the results of integrity assessments to validate the effectiveness of the program so that the operational risk remains as low as reasonably practicable throughout the integrity inspection and assessment cycle. As inspection technology, pipeline materials and construction practices improve with time, and new data on threats and pipeline condition are gathered, our methods of maintaining fitness for service evolves, with a strong focus on continuous improvement. Similar to the US regulatory landscape for integrity management, a significant release could likely lead the CER to impose pressure restrictions which may have an adverse effect on our operations, capital expenditures, earnings, cash flows, financial condition and competitive advantage.

Our pipelines also face economic regulatory risk. Broadly defined, economic regulatory risk is the risk that governments or regulatory agencies reject or revise proposed commercial arrangements, applications or policies, upon which future and current operations are dependent. Our pipelines are subject to the actions of various regulators, including the CER and the FERC, with respect to tariffs and tolls. The rejection or revision of applications for approval of new tariff structures or proposed commercial arrangements and changes in interpretation of existing regulations by courts or regulators could have an adverse effect on our revenues and earnings.

Crude Oil Marketing Business
The Crude Oil Marketing business is regulated by government authorities in the areas of commodity trading, import and export compliance and the transportation of commodities. Non-compliance with governing rules and regulations could result in fines, penalties and operating restrictions. These consequences would have an adverse effect on operations, earnings, cash flows, financial condition and competitive advantage. Mitigation of these potential risks is managed by a regulatory compliance program.

In the US, commodity marketing is regulated by the Commodity Futures Trading Commission, the FERC, the SEC, the Federal Trade Commission, the various commodity exchanges, the US Department of Justice and state regulators. In Canada, provincial and other territorial securities regulators similarly regulate commodity marketing within Canada. These various regulators enforce, among other things, the prohibition of market manipulation, fraud and disruptive trading.

The transportation of crude oil and natural gas liquids by railcar or truck is regulated by the US DOT, Transport Canada and provincial regulation. Each jurisdiction requires compliance with security, safety, emergency management, and environmental laws and regulations related to ground transportation of commodities. Risks associated with transportation of crude or natural gas liquids include unplanned releases, which may require remediation of the affected area. The Crude Oil Marketing business engages third parties, such as Emergency Response Assistance Canada, the Chemical Transportation Emergency Center and the Canadian Transport Emergency Center to assist in such remediation.

Gas Distribution and Storage - Canada
Enbridge Gas Ontario's operations are regulated by the OEB and Enbridge Gaz Quebec's operations are regulated by the Québec Régie de l'énergie. To the extent that the regulators' future actions are different from current expectations, the timing and amount of recovery or refund of amounts recorded in the Consolidated Statements of Financial Position, or amounts that would have been recorded in the Consolidated Statements of Financial Position in the absence of the effects of regulation, could be different from the amounts that are eventually recovered or refunded.

In October 2022, Enbridge Gas Ontario filed its application with the OEB to establish a 2024 through 2028 Incentive Regulation (IR) rate setting framework. The application initially sought approval in two phases to establish 2024 base rates (Phase 1) on a cost-of-service basis and to establish a price cap rate setting mechanism (Phase 2) to be used for the remainder of the IR term (2025-2028). A third phase (Phase 3) has been established with the OEB as part of the Phase 1 Partial Settlement Proposal (Phase 1 Settlement). Phase 3 will address cost allocation and the harmonization of rates and rate classes between legacy rate zones, and is anticipated to be completed in 2025.

In August 2023, the OEB approved the Phase 1 Settlement and in December 2023, the OEB issued its Decision and Order on the remaining unsettled items in Phase 1 (Phase 1 Decision). These decisions include the following findings or orders:

- energy transition risk requires us to carry out a risk assessment to consider further risk mitigation measures in three areas: system access and expansion capital spending, system renewal capital spending and depreciation policy;
- all new small volume customers wishing to connect to natural gas are to pay their full connection costs as an upfront charge (the revenue horizon was set to zero years), rather than through rates over time effective January 2025;
- approval of a harmonized depreciation methodology that reduced the amount of depreciation sought and adjusted asset lives including extensions of service life for certain asset classes;
- the removal of $84 million of undepreciated integration capital costs from 2024 rate base; and
- an increase in equity thickness from 36% to 38% effective 2024.

Enbridge Gas Ontario filed a Notice of Appeal with the Ontario Divisional Court in January 2024 regarding various aspects of the Phase 1 Decision and subsequently filed an amended Notice of Appeal in December 2024 (Amended Appeal). The Amended Appeal focused on two aspects of the Phase 1 Decision: asset class average useful lives for depreciation purposes, and equity thickness. In January 2024, Enbridge Gas Ontario filed a Notice of Motion with the OEB requesting the OEB to review and vary the Phase 1 Decision which was subsequently amended in May 2024 (Amended Motion). The Amended Motion focused on two aspects of the Phase 1 Decision: asset class average useful lives for depreciation purposes, and the recoverability of integration capital. In October 2024, the OEB issued a decision on the Amended Motion and determined that only the issue of integration capital met the threshold to warrant a review. We are currently awaiting an OEB decision on the issue of integration capital.

In May 2024, Bill 165, the *Keeping Energy Costs Down Act,* received royal assent, giving the Government of Ontario time-limited authority to set the revenue horizon for small volume customers, effectively reversing that aspect of the OEB's Phase 1 Decision. Regulations are now in place setting the revenue horizon for new customer connections to 40 years.

In November 2024, the OEB issued its Decision approving the Phase 2 Partial Settlement Proposal (Phase 2 Settlement). The Phase 2 Settlement establishes a price cap IR rate setting mechanism to be used for establishing rates for 2025 – 2028. The price cap mechanism will establish new rates each year through an annual base rate adjustment to migrate an incremental $50 million in capitalized overheads to operating and maintenance costs, annual base rate escalation at inflation less a 0.28% productivity factor, annual updates for certain costs to be passed through to customers, and where applicable, it will provide for the recovery of material unexpected events and discrete incremental capital investments beyond those that can be funded through base rates. The price cap mechanism includes the continuation and establishment of certain deferral and variance accounts, as well as an earnings sharing mechanism that requires Enbridge Gas Ontario to share equally with customers any earnings in excess of 100 basis points over the allowed return on equity (ROE), and 90% of any earnings in excess of 300 basis points over the allowed ROE. Issues not addressed as part of the Phase 2 Settlement proceeded to hearing in December 2024 and a decision is expected in the second quarter of 2025.

Gas Distribution and Storage - US

Our US utilities operations are regulated by the Ohio Commission, the Utah Commission, the Wyoming Commission, the Idaho Commission, and the North Carolina Commission, as well as PHMSA and the US DOT.

Gas Regulation in Ohio

Enbridge Gas Ohio is subject to regulation of rates and other aspects of its business by the Ohio Commission. When necessary, Enbridge Gas Ohio seeks general base rate increases to recover increased operating costs and a fair return on rate base investments. Base rates are set based on the cost-of-service by rate class. A straight-fixed-variable rate design, in which the majority of operating costs are recovered through a monthly charge rather than a volumetric charge, is utilized to establish rates for a majority of Enbridge Gas Ohio’s customers, pursuant to a 2008 rate case settlement.

The Ohio Commission has also approved several stand-alone cost recovery mechanisms to recover specified costs and a return for infrastructure, information technology and integrity or compliance-related projects between general base rate cases.

In October 2023, Enbridge Gas Ohio filed its base rate case and schedules with the Ohio Commission. Enbridge Gas Ohio proposed a non-fuel, base rate annual revenue increase of $212 million, projected 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. The proposed rates would have provided for an ROE of 10.40% compared to the currently authorized ROE of 10.38%. In addition, Enbridge Gas Ohio requested approval for an alternative rate plan for the continuation and modification of certain programs, including Pipeline Infrastructure Replacement (PIR) and Capital Expenditure Program (CEP). On December 18, 2024, Enbridge Gas Ohio filed a Notice of Intent to Modify Filed Positions. The Notice of Intent indicated a willingness to accept a reduced annual revenue requirement increase (from $212 million to $60 million) and, if the reduced position were adopted, to forgo filing a new base rate case until October 31, 2027. The hearing began on January 13, 2025, and remains underway.

In 2008, PIR was introduced, aimed at replacing approximately 25% of its pipeline system. The Ohio Commission has approved Enbridge Gas Ohio's PIR program for capital investments through 2026 with 3% increases of annual capital expenditures per year.

In 2011, CEP was introduced, which enables Enbridge Gas Ohio to defer depreciation expense, property tax expense and carrying costs at the debt rate of 6.5% on capital investments not covered by its PIR program to expand, upgrade or replace its infrastructure and information technology systems, as well as investments necessary to comply with the Ohio Commission or other government regulation.

Gas Regulation in Utah, Wyoming, and Idaho
Enbridge Gas Utah, Enbridge Gas Wyoming, and Enbridge Gas Idaho are subject to regulation of rates and other aspects of its business by the Utah Commission, the Wyoming Commission, and the Idaho Commission, respectively. The Idaho Commission has contracted with the Utah Commission for rate oversight of Enbridge Gas Idaho's operations in a small area of southeastern Idaho. When necessary, Enbridge Gas Utah, Enbridge Gas Wyoming and Enbridge Gas Idaho seek general base rate increases to recover increased operating costs and a fair return on rate base investments. Base rates are set based on the cost-of-service by rate class. Base rates are designed primarily based on rate design methodology in which the majority of operating costs are recovered through volumetric charges. The volumetric charges for the residential and small commercial customers in Utah and Wyoming are subject to revenue decoupling and adjusted for changes in usage per customer.

Gas Regulation in North Carolina
Enbridge Gas North Carolina is subject to regulation of rates and other aspects of its business by the North Carolina Commission. When necessary, Enbridge Gas North Carolina seeks general base rate increases to recover increased operating costs and a fair return on rate base investments. Base rates are set based on the cost-of-service by rate class. Base rates for Enbridge Gas North Carolina are designed primarily based on rate design methodology in which the majority of operating costs are recovered through volumetric charges. The volumetric charges for the residential and commercial customers are subject to revenue decoupling and adjusted for changes in usage per customer.

The North Carolina Commission has approved a standalone cost recovery mechanism to recover specified capital costs and a return for pipeline integrity management infrastructure projects between general base rate cases.

Renewable Power Generation
Renewable Power Generation is subject to numerous operational rules and regulations mandated by governments and applicable regulatory authorities. Breaches of these rules and regulations could result in fines, penalties, operating restrictions and an overall increase in operating and compliance costs.

The North American Electric Reliability Council (NERC) is an international regulatory authority responsible for establishing and enforcing reliability standards to reduce risks to the reliability and security of the grid in Canada, the US, and Mexico. It is subject to oversight from the FERC in the US and provincial governments in Canada. The FERC has authority over many markets in the US and is tasked with ensuring safe, reliable, and secure interstate transmission of electricity, natural gas, and oil. This includes establishing reliability standards, market rates, and determining certain pricing aspects of transmission development and access, among others. NERC and FERC standards and pricing decisions are also updated from time to time and could impact our operations, capital expenditures, earnings, and cash flows, though some of these impacts could be positive for our business.

At the US federal level, our Renewable Power Generation assets are subject to legislation overseen by the US Fish and Wildlife Service, which is aimed at reducing the impact of development and human activity on wildlife, along with other federal environmental permitting legislation. These federal environmental laws are subject to change from time to time, which could require Enbridge to obtain new permits, update practices, or amend operations and operating expenditures.

In Canada, the Federal Government does not generally regulate the electricity sector, though it has imposed a federal carbon price on other sectors via its output-based pricing system and has proposed a Clean Electricity Regulation (CE Regulation) that would require Canada's electricity grid to reach net-zero by 2050 with initial limitations beginning in 2035. The CE Regulation came into effect in December 2024.

Policy changes may also impact our existing assets and the opportunity for new developments. For example, the US enacted *the Inflation Reduction Act* in August 2022, establishing long-term transferable production and investment tax credits for renewable power generation, battery storage projects and for related manufacturing supply chains. Similarly, Canada has passed legislation enabling the Clean Technology Investment Tax Credit (ITC) and published a draft Clean Electricity ITC legislation anticipated to be enacted in mid-2025 focusing on non-taxable entities. Both of these credits would provide refundable ITCs for renewable power generation and battery storage projects. Changes to these programs, including as a result of a change in administration, could impact development plans.

Renewable Power Generation is also subject to provincial and state regulations governing the energy resource mix on the grid, emissions levels of the electricity grid, and market regulations related to emergency operations, extreme weather preparedness, and market participation, among others. These regulations may change from time to time, which could impact Enbridge's operations and increase the costs of participating in regional electricity markets. In 2023, the Texas legislature proposed firming requirements that would require new wind and solar projects to be paired with batteries or other dispatchable power supply either on or offsite to enable more firm supply. These requirements were not enacted; however, they remain an important consideration going forward and heading into the 2025 legislative session. Other state and provincial governments are also prioritizing reliability and more dispatchable generation characteristics in their markets.

Our Renewable Power Generation assets in France and Germany each have federal policies in place and are subject to directives and regulations established and enforced by the European Union (EU). These include the Renewable Energy Directive, the European Green Deal, and ongoing work on financing mechanisms and transmission directives and programs. The EU is also responsible for establishing environmental protection rules and permitting standards. During 2022, member states of the EU introduced extraordinary and temporary measures to address high energy prices including caps and demand reduction goals. As the minimum PPA prices in Germany and France are still honored, there are no negative implications to our PPA prices. The federal policies and regulations in place are subject to change from time to time, which could impact our operations and related expenditures; however, the EU's general direction is to facilitate increased renewable power integration to its grid.

The United Kingdom (UK) government is responsible for establishing renewable energy and carbon pricing policies for the entire UK, as well as long-term electricity sector planning and procurement mechanisms and structure for auctions that are administered at the national level, e.g., England, Scotland, within the UK. Each country within the UK is also responsible for establishing its own environmental and permitting regulations. This process is still ongoing following Brexit and, in some cases, continues to result in more volatile merchant power prices; however, expanded interconnectors to Europe and policies aimed at increasing domestic renewable capacity are in progress. Governments have introduced temporary price controls and other measures, beginning on January 1, 2023, to address the significant increase in energy prices. The impact of merchant exposure on our Renewable Power Generation assets in the UK is limited by fixed revenue payments backed by the UK government.

ENVIRONMENTAL REGULATION

Pipeline Regulation

Our Liquids Pipelines and Gas Transmission assets are subject to numerous federal, state and provincial environmental laws and regulations affecting many aspects of our present and future operations, including air emissions, water quality, water discharge and waste. These laws and regulations generally require us to obtain and comply with a wide variety of environmental licenses, permits and other approvals.

In particular, in the US, compliance with the *Clean Air Act* (CAA) regulatory programs may cause us to incur significant capital expenditures to obtain permits, evaluate off-site impacts of our operations, install pollution control equipment, and otherwise assure compliance. Some equipment in states in which we operate are affected by the Good Neighbor Rule establishing new emission limits for nitrogen oxides. The precise nature of these compliance obligations at each of our facilities has not been finally determined and may depend in part on future regulatory changes. In addition, compliance with new and emerging environmental regulatory programs may significantly increase our operating costs compared to historical levels.

In the US, climate change action is evolving at federal, state and regional levels. On March 8, 2024, the Environmental Protection Agency (EPA) released a final rule to minimize methane emissions for new and existing crude oil and natural gas facilities. Pursuant to federal regulations, we are currently subject to an obligation to report our GHG emissions through the Mandatory Greenhouse Gas Reporting Program at facilities that exceed the reporting threshold of 25,000 metric tons of carbon dioxide equivalent per year. This program was revised to include additional sources and new measurement and calculations methodologies for the oil and gas sector on May 14, 2024, and effective for reporting year 2025. These changes were designed to comply with the *Inflation Reduction Act*'s requirement to revise the program to utilize more empirical data. This data is used to calculate a fee under the Methane Emissions Reduction Program through the Methane Waste Emission Charge that was finalized and published on November 18, 2024. In addition, several states have joined regional GHG initiatives, and a number are developing their own programs that would mandate reductions in GHG emissions. Public interest groups and regulatory agencies are increasingly focusing on the emission of methane associated with natural gas development and transmission as a source of GHG emissions. Based on proposed changes to measure, report and mitigate GHG emissions the expectation is that there will be a significant increase in costs to maintain and report compliance for businesses in our industry.

Canada has adopted a pan-Canadian approach to pricing carbon emissions to incent GHG emission reductions across all sectors of the economy. This approach was adopted in 2016 and entails both a consumer price on carbon, and an intensity-based system for industry which addresses competitiveness and carbon leakage. Provinces and territories may implement their own system of carbon pricing provided it meets the federal benchmark (and if they fail to do so the federal system will be imposed on them). In March 2022, Canada published its 2030 Emissions Reduction Plan (ERP) which builds on the Pan-Canadian Framework, and *Net-Zero Emissions Accountability Act*, and details the roadmap for Canada to meet its domestic climate target of a 40-45% reduction in GHG emissions by 2030 and attaining net-zero emissions by 2050. The ERP details the complementary policies and programs that Canada will enact to enable it to meet its domestic climate goal. Effective April 1, 2024, the federal carbon price was increased to $65 per tonne of carbon dioxide equivalent (tCO2e). This will increase by $15 per tonne each year and rise to $170 per tCO2e in 2030.

Two pending regulations in Canada that are expected to impact our operations include the amended federal methane regulations and the proposed volatile organic compounds (VOC) regulations. The amended methane regulations are part of Canada's broader effort to achieve at least a 75% reduction in methane emissions from the oil and gas sector by 2030, relative to 2012 levels. These regulations would impact Enbridge's Gas Transmission assets to build upon the current regulations to further reduce methane emissions by limiting venting and increasing leak detection. The proposed VOC regulations, if adopted, would impact Enbridge's Liquids Pipelines assets, specifically petroleum liquid storage tanks and loading operations, by requiring emission control equipment on in-scope storage tanks and loading racks. Both regulations are expected to be finalized in the first quarter of 2025; we continue to monitor these developments, including any potential impacts to our business.

Gas Distribution and Storage

Our Gas Distribution and Storage operations, facilities and workers are subject to municipal, provincial, state and federal legislation which regulates the protection of the environment and the health and safety of workers. Environmental legislation primarily includes regulation of spills and emissions to air, land and water; hazardous waste management; the assessment and management of excess soil and contaminated sites; protection of environmentally sensitive areas, and species at risk and their habitats; and the reporting and reduction of GHG emissions.

Gas distribution system operation, as with any industrial operation, has the potential risk of abnormal or emergency conditions, or other unplanned events that could result in releases or emissions exceeding permitted levels. These events could result in injuries to workers or the public, adverse impacts to the environment, property damage and/or regulatory infractions including orders and fines. We could also incur future liability for soil and groundwater contamination associated with past and present site activities.

In addition to gas distribution, we also operate gas storage facilities in Ontario and Ohio, and our Wexpro business develops and produces natural gas reserves. Environmental risk associated with these facilities has the potential for unplanned releases, which could require remediation of the affected area. There would also be potential for fines and orders under environmental legislation, and potential third-party liability claims by any affected landowners.

The gas distribution system and our other operations must maintain environmental approvals and permits from regulators to operate. As a result, these assets and facilities are subject to periodic inspections and/or audits. Reports are submitted to our regulators as required to demonstrate compliance with environmental requirements. Failure to maintain regulatory compliance could result in operational interruptions, fines, and/or orders for additional pollution control technology or environmental mitigation.

As environmental regulations continue to evolve and become more stringent, the cost to maintain compliance and the time required to obtain approvals continues to increase. A recent example includes the implementation of the new excess soil management requirements (Ontario Regulation 406/19) which has resulted in an increase in soil management costs and effort.

As in previous years, in 2024 we reported operational GHG emissions, including emissions from stationary combustion, flaring, venting and fugitive sources to Environment and Climate Change Canada, the Ontario Ministry of Environment, Conservation and Parks, and a number of voluntary reporting programs. In accordance with the provincial GHG regulations, stationary combustion and flaring emissions related to storage and transmission operations were verified in detail by a third-party accredited verifier with no material discrepancies found.

Under the federal government's *Greenhouse Gas Pollution Pricing Act*, a carbon charge took effect on April 1, 2019 at a rate of 3.91 cents/cubic meter (m3) of natural gas and is applicable to the majority of customers. Enbridge Gas Ontario is registered as a natural gas distributor with the Canada Revenue Agency and remits the federal carbon charge on a monthly basis. The charge increases annually on April 1 of each year, and rose to 15.25 cents/m3 in 2024. The federal carbon price increases by $15 per tCO2e each year, and is scheduled to rise to $170 per tCO2e in 2030, which would equate to a federal carbon charge of 32.40 cents/m3 in 2030.

Effective January 1, 2022, Enbridge Gas Ontario transitioned from the federal output-based pricing system to the Ontario Emissions Performance Standards (EPS). Enbridge Gas Ontario is registered with the Ontario Ministry of the Environment, Conservation and Parks (MECP) as a covered facility under the EPS and has an annual compliance obligation for its facility-related stationary combustion and flaring emissions associated with its transmission and storage operations. Enbridge Gas Ontario must remit payment annually on the portion of emissions that exceed its total annual emissions limit.

In June 2024, the MECP launched the Emissions Performance Program (EPP), a program funded by compliance payments collected from EPS. The EPP allows EPS facilities to apply for funding to support projects that reduce eligible GHG emissions at the eligible EPS facility. Enbridge Gas Ontario has identified projects that are potentially eligible for EPP funding and is working with the MECP to submit EPP applications.

Enbridge Gas Ontario applies to the OEB annually through a Federal Carbon Pricing Program application for approval of just and reasonable rates effective April 1 each year to recover the costs associated with the Federal Carbon Charge and EPS Regulation as a pass-through to customers.

Our US gas distribution operations are subject to various federal and state laws and regulations governing the management, storage, treatment, reuse, and disposal of waste materials and hazardous substances. These include the *Resource Conservation and Recovery Act of 1976*, *Comprehensive Environmental Response, Compensation, and Liability Act*, the *Emergency Planning and Community Right-to-Know Act of 1986*, and the *Toxic Substances Control Act of 1976*. Wexpro's operations and construction activities, related to oil and gas production and gas storage wells, generate waste. Completion water is disposed of at commercial disposal facilities, while produced water is either hauled for disposal, evaporated, or injected into company and third party-owned underground injection wells. Wells drilled in tight-gas-sand and shale reservoirs require hydraulic-fracture stimulation to achieve economic production rates and recoverable reserves. The majority of Wexpro's current and future production and reserve potential comes from reservoirs that need hydraulic-fracture stimulation to be commercially viable. Currently, all well construction activities, including hydraulic-fracture stimulation and the management and disposal of hydraulic fracturing fluids, are regulated by federal and state agencies that review and approve all aspects of gas and oil well design and operation.

In 2025, we will report 2024 operational GHG emissions, including emissions from combustion, venting, and fugitive sources, for the first time for our newly acquired US Gas Utilities to the Environmental Protection Agency under the Greenhouse Gas Reporting Program.

Renewable Power Generation
Our Renewable Power Generation assets are subject to a combination of federal, state, provincial and local government agencies. These regulations and laws associated with these agencies affect the development and operations of our renewable power assets and generally require us to assess the environmental landscape and obtain and comply with a variety of environmental licenses, permits and other approvals.

In Canada, our Renewable Power Generation assets are subject to the federal *Species at Risk Act* and provincial regulations that are aimed at mitigating the effects of development and human activity on wildlife. At the US federal level, our assets are subject to legislation overseen by the US Fish and Wildlife Service, which is similarly aimed at reducing the impact of development and human activity on wildlife, along with other federal environmental permitting legislation. These environmental laws (federal, state and provincial) are subject to change from time to time which could require Enbridge to obtain new permits, update practices, or amend operations and operating expenditures.

The regulatory landscape continues to evolve to address new developments within this relatively new industry. In the summer of 2023, the Federal Government of Canada introduced its draft CE Regulation that are intended to achieve a net-zero electricity grid by 2050 with initial limitations beginning in 2035. The Federal Government of Canada released finalized regulations on December 17, 2024 setting limits on GHG emissions from almost all electricity generation units that use fossil fuels. The finalized regulations also include a compliance credit system, and opportunities for credit trading and pooling within federal and provincial frameworks, intended to provide flexibility for operators to meet the new standards.

Similarly, in April 2024, the US EPA finalized regulations for coal-fired and new natural gas-fired power plants designed to reduce emissions 75 percent below 2005 levels by 2035. These regulations require covered facilities to reduce carbon dioxide emissions equivalent to a 90 percent carbon capture and sequestration rate by 2032. Facilities with less than 40 percent capacity rates would be required to adhere to less stringent requirements, including enhanced energy efficiency. These government policies are rapidly evolving, including as a result of changes in governments. We continue to monitor these developments, together with their impact on our business.

Enbridge’s Renewable Power Generation resources are substantially non-emitting.

HUMAN CAPITAL RESOURCES

WORKFORCE SIZE AND COMPOSITION
As at December 31, 2024, we had approximately 14,500 regular employees, including approximately 2,600 unionized employees across our North American operations. This total includes approximately 3,500 employees who joined in 2024 following the close of the Acquisitions of the US Gas Utilities. Overall headcount rises to just over 16,000 if temporary employees and contractors are included. We have a strong preference for direct employment relationships but where we have collectively bargained-for employees, we have mature working relationships with our labor unions and the parties have traditionally committed themselves to the achievement of renewal agreements without a work stoppage.

SAFETY
We believe all injuries, incidents and occupational illnesses are preventable. Our overall focus on employee and contractor safety, continues to result in strong performance compared against industry benchmarks and we are actively engaged in continuous improvement exercises as we pursue our goal of zero incidents.

PRODUCTIVITY AND DEVELOPMENT
We continually invest in our people's personal and professional development and productivity because we recognize their success is our success. Employees are provided access to leading productivity tools and technology, and can opt in to a range of development and growth opportunities through a variety of channels, which encourages employees to build new skills needed for our core and emerging lines of business and the broader energy transition.

EXECUTIVE OFFICERS

The following table sets forth information regarding our executive officers as at February 14, 2025:

Name	Age	Position
Gregory L. Ebel	60	President & Chief Executive Officer
Patrick R. Murray	50	Executive Vice President & Chief Financial Officer
Colin K. Gruending	55	Executive Vice President & President, Liquids Pipelines
Cynthia L. Hansen	60	Executive Vice President & President, Gas Transmission
Michele E. Harradence	56	Executive Vice President & President, Gas Distribution and Storage
Matthew A. Akman	57	Executive Vice President, Corporate Strategy & President, Power
Reginald D. Hedgebeth	57	Executive Vice President, External Affairs and Chief Legal Officer
Maximilian G. Chan	46	Senior Vice President & Corporate Development Officer
Laura J. Sayavedra	57	Senior Vice President, Safety, Projects & Chief Administrative Officer

Gregory L. Ebel was appointed President and Chief Executive Officer (CEO) on January 1, 2023. Mr. Ebel is also a member of the Enbridge Board of Directors. Mr. Ebel served as Chair of the Enbridge Board of Directors following the merger of Enbridge and Spectra Energy Corp (Spectra Energy) in 2017 until January 1, 2023. Prior to that time, he served as Chairman, President and CEO of Spectra Energy from 2009 until February 27, 2017. Previously, Mr. Ebel also served as Spectra Energy's Group Executive and Chief Financial Officer beginning in 2007, President of Union Gas Limited from 2005 until 2007, and Vice President, Investor & Shareholder Relations of Duke Energy Corporation from 2002 until 2005.

Patrick R. Murray was appointed Executive Vice President & Chief Financial Officer (CFO) on July 1, 2023. Mr. Murray has oversight of Enbridge's financial affairs including investor relations, financial reporting, financial planning, treasury, tax, insurance, risk and audit management functions. He also leads Enbridge's technology and information services teams. Prior to assuming his current role, Mr. Murray was Senior Vice President & Chief Accounting Officer of Enbridge from June 2020 to June 2023, Vice President, Financial Planning & Analysis and Controller from June 2019 to May 2020, and Vice President, Financial Planning & Analysis from February 2017 to June 2019. Mr. Murray joined Enbridge over 27 years ago and has held a variety of roles within internal audit, corporate accounting, investor relations, treasury, and corporate development during that time.

Colin K. Gruending was appointed Executive Vice President and President, Liquids Pipelines on October 1, 2021. Mr. Gruending is responsible for the overall leadership and operations of Enbridge's Liquids Pipelines business. Previously, he served as our Executive Vice President and Chief Financial Officer from June 2019 to October 2021; Senior Vice President, Corporate Development and Investment Review from May 2018 to June 2019; and Vice President, Corporate Development and Investment Review from February 2017 to May 2018.

Cynthia L. Hansen was appointed Executive Vice President and President, Gas Transmission on March 1, 2022. Ms. Hansen is responsible for the overall leadership and operations of Enbridge's natural gas pipeline and midstream business across North America. Previously, she served as our Executive Vice President, Gas Distribution and Storage from June 2019 to March 2022 and as Executive Vice President, Utilities and Power Operations from February 2017 to June 2019. Ms. Hansen is also the Executive Sponsor for Asset and Work Management Transformation across Enbridge, working with other business unit leaders.

Michele E. Harradence was appointed Executive Vice President & President, Gas Distribution and Storage on March 5, 2023. She is responsible for the overall leadership and operations of Enbridge's Gas Distribution and Storage business across North America. Prior to assuming her current role, Ms. Harradence was Senior Vice President & President, Gas Distribution and Storage from March 2022 to March 2023. Prior thereto, she was Senior Vice President and Chief Operations Officer of Enbridge's Gas Transmission and Midstream business unit from June 2019 to March 2022 and Senior Vice President Operations, Gas Transmission and Midstream from February 2017 to June 2019.

Matthew A. Akman was appointed Executive Vice President, Corporate Strategy & President, Power on March 5, 2023. Mr. Akman is responsible for the overall leadership and operations of Enbridge's power business and also leads our new energy technologies and corporate strategy efforts. Prior to assuming his current role, Mr. Akman was Senior Vice President, Corporate Strategy & President, Power from January 2023 to March 2023. Prior thereto, he was Senior Vice President, Strategy, Power & New Energy Technologies from October 2021 to December 2022, and Senior Vice President, Strategy & Power from June 2019 to October 2021. Mr. Akman joined Enbridge in early 2016 as our head of Corporate Strategy and also previously held responsibilities for Corporate Development and Investor Relations.

Reginald D. Hedgebeth was appointed Executive Vice President, External Affairs and Chief Legal Officer on January 1, 2024. Mr. Hedgebeth leads our legal, public affairs, communications & sustainability, corporate security and aviation teams across the organization. Prior to joining Enbridge, Mr. Hedgebeth served as Chief Legal Officer of Capital Group from January 2021 to June 2023, Executive Vice President, General Counsel and Chief Administrative Officer of Marathon Oil Corporation from April 2017 to December 2020 and, prior to its merger with Enbridge in 2017, General Counsel, Corporate Secretary and Chief Ethics and Compliance Officer for Spectra Energy.

Maximilian G. Chan was appointed Senior Vice President & Corporate Development Officer on March 1, 2022. He was later appointed to the Executive Leadership team on May 8, 2023. Mr. Chan is responsible for the oversight of mergers and acquisitions, capital allocation, investment review, integration and corporate growth objectives. Prior to assuming his current role, Mr. Chan was Vice President, Treasury and Head of Enterprise Risk for Enbridge from February 2020 to March 2022, and Vice President, Treasury from July 2018 to February 2020.

Laura J. Sayavedra was appointed Senior Vice President, Safety, Projects & Chief Administrative Officer on January 1, 2024. Ms. Sayavedra is responsible for the oversight of our safety, capital project execution, human resources, real estate and supply chain management functions. Prior to assuming her current role, Ms. Sayavedra was Senior Vice President, Safety & Reliability, Projects and Unify from March 2022 to December 2023. Prior to that, she led Finance Transformation at Enbridge, and prior to its merger with Enbridge in 2017, was also Vice President & Treasurer for Spectra Energy, and CFO of Spectra Energy Partners LP. She has held various finance, strategy, and business development executive leadership roles.

ADDITIONAL INFORMATION

Additional information about us is available on our website at www.enbridge.com, on SEDAR+ at www.sedarplus.ca and on EDGAR at www.sec.gov. The aforementioned information is made available in accordance with legal requirements and is not, unless otherwise specifically stated, incorporated by reference into this Annual Report on Form 10-K. We make available free of charge, through our website, annual reports on Form 10-K, quarterly reports on Form 10-Q and current reports on Form 8-K and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Exchange Act, as well as proxy statements, as soon as reasonably practicable after we electronically file such material with, or furnish it to, the SEC. Reports, proxy statements and other information filed with the SEC may also be obtained through the SEC's website (www.sec.gov).

ENBRIDGE GAS INC.
Additional information about Enbridge Gas Inc. (operating as Enbridge Gas Ontario) can be found in its annual information form, financial statements and MD&A for the year ended December 31, 2024, which have been filed with the securities commissions or similar authorities in each of the provinces of Canada. These documents contain detailed disclosure with respect to Enbridge Gas Ontario and are publicly available on SEDAR+ at www.sedarplus.ca. These documents are not, unless otherwise specifically stated, incorporated by reference into this Annual Report on Form 10-K.

ENBRIDGE PIPELINES INC.
Additional information about Enbridge Pipelines Inc. (EPI) can be found in its annual information form, financial statements and MD&A for the year ended December 31, 2024, which have been filed with the securities commissions or similar authorities in each of the provinces of Canada. These documents contain detailed disclosure with respect to EPI and are publicly available on SEDAR+ at www.sedarplus.ca. These documents are not, unless otherwise specifically stated, incorporated by reference into this Annual Report on Form 10-K.

WESTCOAST ENERGY INC.
Additional information about Westcoast Energy Inc. (Westcoast) can be found in its financial statements and MD&A for the year ended December 31, 2024, which have been filed with the securities commissions or similar authorities in each of the provinces of Canada. These documents contain detailed disclosure with respect to Westcoast and are publicly available on SEDAR+ at www.sedarplus.com. These documents are not, unless otherwise specifically stated, incorporated by reference into this Annual Report on Form 10-K.

ITEM 1A. RISK FACTORS

The following risk factors could materially and adversely affect our business, operations, financial results, market price or value of our securities. This list is not exhaustive, and we place no priority or likelihood based on order of presentation or grouping under sub-captions.

RISKS RELATED TO CLIMATE CHANGE

Climate change risks could adversely affect our reputation, strategic plan, business, operations and financial results, and these effects could be material.
Climate change is a systemic risk that presents both physical and transition risks to our organization. A summary of these risks is outlined below. Given the interconnected nature of climate change-related impacts, we also discuss these risks within the context of other risks impacting Enbridge throughout *Item 1A. Risk Factors*. Climate change and its associated impacts may also increase our exposure to, and magnitude of, other risks identified in *Item 1A. Risk Factors*. Our business, financial condition, results of operations, cash flows, reputation, access to and cost of capital or insurance, business plans and strategy may all be materially adversely impacted as a result of climate change and its associated impacts.

PHYSICAL RISKS
Climate-related physical risks, resulting from changing and more extreme weather, can damage our assets and affect the safety and reliability of our operations. Climate-related physical risks may be acute or chronic. Acute physical risks are those that are event-driven, including increased frequency and severity of extreme weather events, such as heavy snowfall, heavy rainfall, floods, landslides, fires, hurricanes, cyclones, tornados, tropical storms, ice storms, and extreme temperatures. Chronic physical risks are longer-term shifts in climate patterns, such as long-term changes in precipitation patterns, or sustained higher temperatures, which may cause sea level rises or chronic heat waves.

Our assets and operations are exposed to potential damage or other negative impacts from these kinds of events, which have in the past resulted and could in the future result in reduced revenue from business disruption or reduced capacity and may also lead to increased costs due to repairs and required adaptation measures. We have experienced operational interruptions and damage to our assets from such weather events in the past, and we expect to continue to experience climate-related physical risks in the future, potentially with increasing frequency or severity. Such events may also result in personal injury, loss of life.

TRANSITION RISKS
The transition to a lower-carbon economy involves policy, legal, technology and market changes which may, in turn, increase our cost of operations and influence stakeholder sentiment and decisions about Enbridge, including potentially reducing the demand for some of our services, which could result in a decrease in profitability or reduction in the value of our assets. Transition risks include the following categories:

- ***Policy and legal risks***
  Policy and legal risks may result from evolving government policy, legislation, regulations and regulatory decisions focused on climate change, as well as changing political and public opinion, stakeholder opposition, legal challenges, litigation and regulatory proceedings. Foreign and domestic governments and regulators continue to evaluate and implement policy, legislation, regulations and decisions aimed at mitigating the impacts of and adapting to climate change, including measures to reduce GHG emissions and shift to lower-carbon sources of energy. Such policies, laws and regulations vary at the federal, state, provincial and municipal levels in which Enbridge operates and are continually evolving. Rules, standards, and methodologies for setting climate-related goals and for measuring and reporting climate-related information are still developing. At the same time, we have seen the rise of anti-ESG activism, creating competing stakeholder priorities and increasing

uncertainty. As a result, our climate-related goals and disclosures are based on assumptions that are subject to change. Collectively, these measures have resulted and are expected to continue to result in increased costs to us. Enbridge adheres to a number of carbon-pricing mechanisms, including explicit carbon prices (i.e., in BC) and implicit carbon prices (i.e., Canadian federal output-based pricing system). In Canada, the federal government has proposed new Clean Electricity Regulations and is considering options to cap and cut GHG emissions from the oil and gas sector, which may impact our business. Such evolving policy, legislation and regulation could impact commodity demand, and the overall energy mix we deliver and may result in significant expenditures and resources, as well as increased costs for our customers. In recent years, there has also been changing political and public opinion and stakeholder opposition in relation to parts of our business and industry, as well as an increase in climate-related litigation and regulatory action against companies, all of which could impact our reputation, strategy and financial results.

- ***Technology risks***
  Executing our strategic priorities, including participating in the energy transition over time and attaining our GHG emissions reduction goals, depends, in part, on technological improvements and innovation. This includes the development and use of emerging technologies, such as renewable power and other lower-carbon energy infrastructure. Such technological developments could require significant capital expenditures and resources and may, impact our competitiveness. GHG emissions reduction technology may not materialize as expected, which could make it more difficult to reduce emissions and meet our ESG goals.

- ***Market risks***
  Concerns about climate change, increased demand for lower-carbon forms of energy and new energy technologies, changing customer behavior, and reduced energy consumption could impact the demand for our services or our securities. In recent years, certain investors, lenders and insurers have taken or are contemplating actions to decrease the carbon intensity of their portfolios or reduce or cease support for the fossil fuel industry. Such measures could result in increased costs to manage these risks and could negatively impact our access to and cost of capital, as well as demand for, or value of, our securities or our services. Uncertainty in market signals, such as abrupt and unexpected shifts in energy costs and demands, including due to climate change concerns, could impact revenue through reduced throughput volumes on our pipeline transportation systems.

- ***Reputational risks***
  Companies across all sectors and industries are facing changing expectations and increased scrutiny from stakeholders related to their approach to climate change and GHG emissions. Companies in the energy industry are experiencing stakeholder opposition to their operations and infrastructure projects. Enbridge's ESG goals, sustainability-related activities, commitments, and plans, including climate-related information and data, are based on various assumptions, estimates, judgments, risks, and uncertainties. Achieving these ESG goals and commitments will require collective efforts and actions from a wide range of stakeholders, much of which is beyond our control, and there can be no assurance that the impact of these efforts and actions will be realized. Our ESG goals and pathways for reducing operational emissions will continue to evolve and may need to be restated, modified, or recalibrated as data improves, standards, methodologies, metrics, and measurements mature, and as legislation, regulations, policies, and stakeholder sentiment evolve. If we experience challenges, or perceived challenges in achieving our climate-related goals, are not able to meet future climate-related, emissions, or other regulatory or reporting requirements, or are not able to meet or manage stakeholder expectations regarding climate change or disclosure of climate-change information (including potential allegations of greenwashing), it could negatively impact our reputation or investor sentiment and could expose us to government enforcement actions or litigation, which may, in turn, impact our business, operations or financial results.

RISKS RELATED TO OPERATIONAL DISRUPTION OR CATASTROPHIC EVENTS

Operation of complex energy infrastructure involves many hazards and risks that may adversely affect our business, financial results, the environment, relationships with stakeholders, and our reputation.

These operational risks include adverse weather conditions, natural disasters, accidents, the breakdown or failure of equipment, processes or human error, and lower than expected levels of operating capacity and efficiency. These operational risks could be catastrophic in nature.

Operational risk is also intensified by exposure to severe weather conditions and natural disasters, including those related to climate change, which may affect the safety and reliability of our operations, including, but not limited to heavy snowfall, heavy rainfall, floods, landslides, fires, hurricanes, cyclones, tornados, tropical storms, ice storms, and extreme temperatures, and chronic physical risks, such as long-term changes in precipitation patterns, or sustained higher temperatures.

Our assets and operations are exposed to potential damage or other negative impacts from these operational risks, which could result in reduced revenue from business disruption or reduced capacity and may also lead to increased costs due to repairs and required adaptation measures. Such events have led to, and could in the future lead to, rupture or release of product from our pipeline systems and facilities, resulting in damage to property and the environment, personal injury or loss of life. Such an incident has in the past, and could in the future, result in substantial losses for which insurance may not be sufficient or available and for which we may bear part or all of the cost, thereby negatively impacting earnings. Such incidents could also have lasting reputational impacts and could impair our relationships with various stakeholders. For pipeline and storage assets located near populated areas, including residential communities, commercial business centers, industrial sites and other public gathering locations, the level of damage resulting from these events could be greater.

We have experienced such events in the past and expect to continue to incur significant costs in preparing for or responding to operational risks and events. We expect to continue to experience climate-related physical risks, potentially with increasing frequency and severity, and we cannot guarantee that we will not experience catastrophic or other events in the future. In addition, we have in the past, and could in the future, be subject to litigation and significant fines and penalties from regulators in connection with any such events.

A service interruption could have a significant impact on our operations, and negatively impact financial results, relationships with stakeholders and our reputation.

A service interruption due to a major power disruption, curtailment of commodity supply, operational incident, security incident (cyber or physical), availability of gas supply or distribution, or other reasons, could have a significant impact on our operations and negatively impact financial results, relationships with stakeholders, our reputation or the safety of our end-use customers. Service interruptions that impact our crude oil and natural gas transportation services can negatively impact shippers' operations and earnings as they are dependent on our services to move their product to market or fulfill their own contractual arrangements, and this has in the past led to and may again lead to claims against us. We have experienced, and may again experience, service interruptions, restrictions or other operational constraints, including in connection with the kinds of operational incidents referred to in the previous risk factor.

Our operations involve safety risks to the public and to our workers and contractors.
Enbridge assets may change over time and operate over a broad geographic area. These assets include liquids pipelines, gas transmission, and gas distribution systems which are operated near populated areas. A major incident involving these assets has resulted in and may again result in injury or loss of life to members of the public. In addition, given the natural hazards inherent in our operations, our workers and contractors are subject to personal safety risks. A public safety incident or an injury or loss of life to our workers or contractors, which we have experienced in the past and, despite the precautions we take, may experience in the future, could result in reputational damage to us, legal claims, material repair costs or increased operating and insurance costs.

Cyber attacks and other cybersecurity incidents pose threats to our technology systems and could materially adversely affect our business, operations, reputation or financial results.
Our business is dependent upon information systems and other digital technologies for controlling our plants, pipelines and other assets, processing transactions and summarizing and reporting results of operations. With the evolution of AI, our business has incorporated AI into our operations in order to gain efficiencies and productivity in our day-to-day operations, which has the potential to increase technology and cybersecurity risks. The secure processing, maintenance and transmission of information is critical to our operations.

Cybersecurity risks have increased in recent years as a result of the proliferation of new technologies and the increased sophistication of cyber attacks and financially-motivated cybercrime, as well as international and domestic political factors, including geopolitical tensions, armed hostilities, war, civil unrest, sabotage, terrorism and state-sponsored or other cyber espionage. Human error or malfeasance can also contribute to a cyber incident, and cyber attacks can be internal as well as external and occur at any point in our supply chain. Because of the critical nature of our infrastructure and our use of information systems and other digital technologies to control our assets, we face a heightened risk of cybersecurity incidents, such as ransomware, theft, misplaced or lost data, programming errors, phishing attacks, denial of service attacks, acts of vandalism, computer viruses, malware, hacking, malicious attacks, software vulnerabilities, employee errors and/or malfeasance, or other attacks, security or data breaches or other cybersecurity incidents. Cyber threat actors have attacked and continue to threaten to attack energy infrastructure, including our assets, and various government agencies have increasingly stressed that these attacks are targeting critical infrastructure, including pipelines, public utilities, and power generation facilities, and are increasing in sophistication, magnitude, and frequency. Additionally, these risks may escalate during periods of heightened geopolitical tensions. In addition, new cybersecurity legislation, regulations and orders have been recently implemented or proposed, resulting in additional actual and anticipated regulatory oversight and compliance requirements, which will require significant internal and external resources. We cannot predict the potential impact to our business of potential future legislation, regulations or orders relating to cybersecurity.

We have experienced an increase in the number of attempts by external parties to access our systems or our company data without authorization, and we expect this trend to continue. Although we devote significant resources and security measures to prevent unwanted intrusions and to protect our systems and data, whether such data is housed internally or by external third parties, we and our third-party vendors have experienced, and expect to continue to experience, cyber attacks of varying degrees in the conduct of our business, including denial of service attacks. To date, these prior cyber attacks have not, to our knowledge, had a material adverse effect on our business, operations or financial results. However, we have experienced an increasing number of cybersecurity threats in recent years and there is a risk that any such incidents could have a material adverse effect on us in the future.

Our technology systems or those of our vendors or other service providers are expected to become the target of further cyber attacks or security breaches which could compromise our data and systems or our access thereto by us, our customers or others, affect our ability to correctly record, process and report transactions, result in the loss of information, or cause operational disruption or incidents. There can be no assurance that our business continuity plans will be completely effective in avoiding disruption and business impacts. Furthermore, we and some of our third-party service providers (who may in turn also use third-party service providers) collect, process or store sensitive data in the ordinary course of our business, including personal information of our employees, residential gas distribution customers, land owners and investors, as well as intellectual property or other proprietary business information of ours or our customers or suppliers. In light of the Acquisitions, due to their large residential customer bases, we and some of our third-party services providers will process increasing amounts of personal information.

As a result of the foregoing, we could experience loss of revenues, repair, remediation or restoration costs, regulatory action, fines and penalties, litigation, breach of contract or indemnity claims, cyber extortion, ransomware, implementation costs for additional security measures, loss of customers, customer dissatisfaction, reputational harm, liability under laws that protect the privacy of personal information, other adverse consequences, or other costs or financial loss. In light of the Acquisitions, these risks may be heightened, and the consequences magnified. Regardless of the method or form of cyber attack or incident, any or all of the above could materially adversely affect our reputation, business, operations or financial results.

In addition, a cyber attack could occur and persist for an extended period without detection. Any investigation of a cyber attack or other security incident may be inherently unpredictable, and it would take time before the completion of any investigation and availability of full and reliable information. During such time, we may not know the extent of the harm or how best to remediate it, and certain errors or actions could be repeated or compounded before they are discovered and remediated, all or any of which could further increase the costs and consequences of a cyber attack or other security incident, and our remediation efforts may not be successful. The inability to implement, maintain and upgrade adequate safeguards could materially and adversely affect our results of operations, cash flows, and financial condition. Moreover, recent rulemakings may require us to disclose information about a cybersecurity incident before it has been completely investigated or remediated in full or even in part. As cyber attacks continue to evolve, we may be required to expend significant additional resources to continue to modify or enhance our protective measures or to investigate and remediate any information security vulnerabilities.

Furthermore, media reports about a cyber attack or other significant security incident affecting Enbridge, whether accurate or not, or, under certain circumstances, our failure to make adequate or timely disclosures to the public, law enforcement, other regulatory agencies or affected individuals following any such event, whether due to delayed discovery or otherwise, could negatively impact our operating results and result in other adverse consequences, including damage to our reputation or competitiveness, harm to our relationships with customers, partners, suppliers, investors, and other third parties, interruption to our management, remediation or increased protection costs, significant litigation or regulatory action, fines or penalties, all of which could materially adversely affect our business, operations, reputation or financial results.

Terrorist attacks and threats, escalation of military activity in response to these attacks or acts of war, other civil unrest or activism, or geopolitical uncertainty could adversely affect our business, operations or financial results.

Terrorist attacks and threats (which may take the form of cyber attacks, as outlined above), escalation of military activity, armed hostilities, war, sabotage, or civil unrest or activism may have significant effects on general economic conditions and may cause fluctuations in consumer confidence and spending and market liquidity, each of which could adversely affect our business. Future terrorist attacks, rumors or threats of war, actual conflicts involving the US or Canada, or military or trade disruptions may significantly affect our operations and those of our customers. Strategic critical infrastructure targets, such as energy-related assets, are at greater risk of cyber attack and may be at greater risk of other future attacks than other targets in the US and Canada. Enbridge's infrastructure and projects under construction could be direct targets or indirect casualties of a cyber or physical attack. In addition, increased environmental activism against construction and operation of energy infrastructure could potentially result in work delays, reduced demand for our products and services, new legislation or public policy or increased stringency thereof, or denial or delay of permits and rights-of-way. Enbridge also faces risks related to international relations and geopolitical events. Factors such as political, economic, or social instability, trade disputes, increased tariffs, changes in laws, strict regulations, and shifts in political leadership can lead to higher commodity prices and affect energy availability and costs.

Pandemics, epidemics or infectious disease outbreaks may adversely affect local and global economies and our business, operations or financial results.

Disruptions caused by pandemics, epidemics or infectious disease outbreaks could materially adversely affect our business, operations, financial results and forward-looking expectations. Governments' emergency measures to combat the spread could include restrictions on business activity and travel, as well as requirements to isolate or quarantine. The duration and magnitude of such impacts will depend on many factors that we may not be able to accurately predict. COVID-19 and government responses interrupted business activities and supply chains, disrupted travel, and contributed to significant volatility in the financial and commodity markets.

Disruptions related to pandemics, epidemics or infectious disease outbreaks could have the effect of heightening many of the other risks described in this *Item 1A. Risk Factors*.

RISKS RELATED TO OUR BUSINESS AND INDUSTRY

There are utilization risks with respect to our assets.

With respect to our Liquids Pipelines assets, we are partially exposed to throughput risk on the Canadian Mainline, and we are exposed to throughput risk under certain tolling agreements applicable to other Liquids Pipelines assets, such as the Lakehead System. A decrease in volumes transported can directly and adversely affect our revenues and earnings. Factors such as changing market fundamentals, capacity bottlenecks, regulatory restrictions, maintenance and operational incidents on our system and upstream or downstream facilities, and increased competition can all impact the utilization of our assets. Market fundamentals, such as commodity prices and price differentials, weather, gasoline prices and consumption, tariffs, alternative and new energy sources and technologies, and global supply disruptions outside of our control can impact both the supply of and demand for crude oil and other liquid hydrocarbons transported on our pipelines.

With respect to our Gas Transmission assets, gas supply and demand dynamics continue to change due to shifts in regional and global production and consumption. These shifts can lead to fluctuations in commodity prices and price differentials, which could result in our system not being fully utilized in some areas. Other factors affecting system utilization include operational incidents, regulatory restrictions, system maintenance, and increased competition.

With respect to our Gas Distribution and Storage assets, customers of our gas distribution franchises are billed on both a fixed charge and volumetric basis and our ability to collect the total revenue requirement (the cost of providing service, including a reasonable return to the utility) in certain jurisdictions depends on achieving the forecast distribution volume established in the rate-making process. The probability of realizing such volume is contingent upon four key forecast variables: weather, economic conditions, pricing of competitive energy sources and growth in the number of customers. Weather is a significant driver of delivery volumes, given that a significant portion of our gas distribution customer base uses natural gas for space heating. Our ability to add new customers could be impacted by market conditions affecting housing activity such as interest rates, affordability levels, and energy transition. Sales and transportation service to large volume commercial and industrial customers are more susceptible to prevailing economic conditions. As well, the pricing of competitive energy sources affects volume distributed to these sectors, as some customers have the ability to switch to an alternate fuel. Even in those circumstances where we attain our respective total forecast distribution volume, our gas distribution business may not earn its expected ROE due to other forecast variables, such as fluctuations in the mix between higher- and lower-margin customers. All of our gas distribution businesses remain at risk for the actual versus forecast of large volume contract commercial and industrial volumes.

With respect to our Renewable Power Generation assets, earnings from these assets are highly dependent on weather and atmospheric conditions as well as continued operational availability of these energy producing assets. While the expected energy yields for Renewable Power Generation projects are predicted using long-term historical data, wind and solar resources are subject to natural variation from year-to-year and from season-to-season. Any prolonged reduction in wind or solar resources at any of the Renewable Power Generation facilities could lead to decreased earnings and cash flows. Additionally, inefficiencies or interruptions of Renewable Power Generation facilities due to operational disturbances or outages resulting from weather conditions or other factors, could also impact earnings.

Our assets vary in age and were constructed over many decades, which causes our inspection, maintenance or repair costs to increase.
Our pipelines vary in age and were constructed over many decades. Pipelines are generally long-lived assets, and pipeline construction, including coating techniques have changed over time. Depending on the era of construction and construction techniques, some assets require more frequent inspections, which have resulted in and are expected to continue to result in increased maintenance or repair costs in the future. Any significant increase in these expenditures could adversely affect our business, operations or financial results.

Competition may result in a reduction in demand for our services, fewer project opportunities or assumption of risk that results in weaker or more volatile financial performance than expected.
Our Liquids Pipelines business faces competition from competing carriers available to ship liquid hydrocarbons to markets in Canada, the US and internationally and from proposed pipelines that seek to access basins and markets currently served by our Liquids Pipelines. Competition among existing pipelines is based primarily on the cost of transportation, access to supply, the quality and reliability of service, contract carrier alternatives and proximity to markets. The commodities transported in our pipelines currently, or are increasingly expected to, compete with other emerging alternatives for end-users, including, but not limited to, electricity, electric batteries, biofuels, and hydrogen. Additionally, we face competition from alternative storage facilities. Our natural gas transmission and storage business competes with similar facilities that serve our supply and market areas in the transmission and storage of natural gas. The natural gas transported and distributed in our business also competes with other forms of energy available to our customers and end-users, including electricity, coal, propane, fuel oils, and renewable energy. Our Renewable Power Generation business faces competition in the procurement of long-term power purchase agreements and from other fuel sources in the markets in which we operate. Competition in all of our businesses, including competition for new project development opportunities, could have a negative impact on our business, financial condition or results of operations.

Completion of our secured projects and maintenance programs are subject to various regulatory, operational and market risks, which may affect our ability to drive long-term growth.
Our project execution continues to face challenges with intense scrutiny on regulatory and environmental permit applications, politicized permitting, public opposition including protests, action to repeal permits, and resistance to land access.

Continued challenges with global supply chains have created unpredictability in materials cost and availability. Labor shortages and inflationary pressures have increased the costs of engineering and construction services. Governments in Canada and the US have enacted or proposed legislation and policies that have the potential to disrupt global and North American supply chains, which may, in turn, disrupt our project execution. They have also enacted legislation and policies relating to forced labor and child labor in supply chains which require the company to, among other things, report on the steps taken in the previous year to mitigate the risk of forced labor or child labor in our supply chain, and these requirements continue to evolve and may impact our supply chain.

Other events that can delay, and have in the past delayed project completion and increased anticipated costs include contractor or supplier non-performance, extreme weather events or geological factors beyond our control.

The effects of US and Canadian Government policies on tariffs and trade relations between Canada and the US are uncertain and could adversely impact us.
The potential imposition of trade tariffs by the US on imports from Canada, together with retaliatory tariffs by Canada on imports from the US, and other potential measures, including tariffs, duties, fees, economic sanctions or other trade measures, present risks to our business operations. Such measures, the nature, extent and timing of which are uncertain, could lead to increased costs for us and our customers and reduced demand for Canadian energy. The potential for such measures introduces uncertainty in North American energy markets, possibly disrupting supply chains and access to capital markets and jeopardizing our competitiveness, and could significantly impact our business. The US Government has also stated its interest in renegotiating and altering the Agreement between the United States of America, Mexico and Canada (USMCA), which could further impact the energy market and our business.

Changing expectations of stakeholders and government policies regarding sustainability, ESG, climate change, and environmental protection practices continue to evolve and diverge, and an inability to meet these requirements and expectations could erode stakeholder trust and confidence, damage our reputation, influence actions or decisions about Enbridge and industry and have negative impacts on our business, operations or financial results.
Companies across all sectors and industries are facing changing expectations and increasing scrutiny from a wide range of stakeholders related to their approach to sustainability and ESG matters of greatest relevance to their business and to their stakeholders. Our and other energy companies' customers, shareholders, employees and other stakeholders have diverse expectations, demands and perspective on these topics, which are continuing to evolve. For example, companies in the energy industry, including Enbridge, have experienced stakeholder opposition to their operations and infrastructure projects, as well as organized opposition to the fossil fuel industry in general. Changing expectations of our practices and performance across these areas may result in or create exposure to new or heightened risks, which may include higher costs, project delays or cancellations, loss of ability to secure new growth opportunities or permits, restrictions on or the cessation of operations due to increasing pressure on governments and regulators, public opposition including protests, activism and legal action, such as the legal challenges to the operation of Line 5 in Michigan and Wisconsin. We may not be able to meet the diverse expectations and demands of all of our stakeholders, which could result in adverse publicity, harm our reputation, lead to claims against us and affect our relationships with our customers and employees, and subject us to legal and operational risks, any of which could have a material adverse effect on our business.

Our operations, projects and growth opportunities require us to have strong relationships with key stakeholders, including local communities, Indigenous groups and others directly impacted by our activities, as well as governments, regulatory agencies, investors and investor advocacy groups, investment funds, financial institutions, insurers and others, some of whom are increasingly focused on sustainability and ESG practices and performance. Enhanced public awareness of climate change has driven an increase in demand for lower-carbon forms of energy. In recent years, certain investors have been increasing investments in lower-carbon assets and businesses while decreasing the carbon intensity of their portfolios through, among other measures, divestment of companies with higher exposure to GHG-intensive operations and products. Commercial and investment banks and insurers have been pressured to reduce or cease providing financing and insurance coverage to the fossil fuel industry. Managing these risks requires significant effort and resources. Potential impacts could also include changing investor sentiment, impaired access to and increased cost of capital, and adverse impacts to the demand for, or value of, our services or our securities.

In recent years, geopolitical uncertainty, slowing Canadian economy and continuing inflationary pressures have underscored the critical need for access to secure, affordable energy. The pace and scale of the transition to a lower-emission economy may pose a risk if Enbridge diversifies either too quickly or too slowly. Similarly, unexpected shifts in energy demands, including due to climate change concerns, can impact revenue through, for example, reduced throughput volumes on our pipeline transportation systems.

The costs associated with meeting our ESG goals, including our GHG emissions reduction goals, could be significant. There is also a risk that some or all of the expected benefits and opportunities of achieving our ESG goals may fail to materialize, may cost more than anticipated to achieve, may not occur within the anticipated time periods, may fail to meet changing stakeholder expectations or may be challenged. Similarly, there is a risk that emissions reduction technologies do not materialize as expected, making it more difficult to reduce emissions. If we experience challenges, or perceived challenges, in achieving our ESG goals, meeting climate-related regulatory or reporting requirements, or meeting or managing stakeholder expectations regarding sustainability and ESG issues, it could have a negative impact on our reputation or investor sentiment or expose us to government enforcement actions or litigation, which may, in turn, impact our business, operations or financial results.

Our forecasted assumptions may not materialize as expected, including on our expansion projects, acquisitions and divestitures.

We evaluate expansion projects, acquisitions and divestitures on an ongoing basis. Planning and investment analysis is highly dependent on accurate forecasting and the use of appropriate assumptions and to the extent that these assumptions do not materialize, financial performance may be lower or more volatile than expected. Volatility and unpredictability in the economy, both locally and globally, and changes in cost estimates, project scoping and risk assessment could result in a loss of profits. Similarly, uncertainty in market signals, such as abrupt and unexpected shifts in energy costs and demands, have impacted and may in the future impact revenue, for example, from reduced throughput volumes on our pipeline transportation systems.

We may encounter difficulties integrating the US Gas Utilities into our business in a successful manner, which may negatively affect the benefits we expect to obtain from the Acquisitions.

In 2024, we completed the Acquisitions of the US Gas Utilities.

The success of the Acquisitions will depend on, among other things, our ability to integrate the US Gas Utilities into our business in a manner that facilitates growth opportunities and achieves anticipated results. There is a significant degree of difficulty and management distraction inherent in the process of integrating an acquisition, including challenges integrating certain operations and functions, technologies, organizations, procedures, policies and operations, cultural differences, and the retention of key personnel. The integration may be complex and time-consuming and involve delays or additional and unforeseen expenses. The integration process and other disruptions resulting from the Acquisitions may also disrupt our ongoing business.

Any failure to realize the anticipated benefits of the Acquisitions, additional unanticipated costs or other factors could negatively impact our earnings or cash flows, decrease or delay any beneficial effects of the Acquisitions and negatively impact our business, financial condition and results of operations.

Our insurance coverage may not fully cover our losses in the event of an accident, natural disaster or other event, and we may encounter increased cost arising from the maintenance of, or lack of availability of, insurance.

Our operations are subject to many hazards inherent in our industry as described in this *Item 1A. Risk Factors*. We maintain an insurance program for Enbridge, our subsidiaries and certain of our affiliates, to mitigate a certain portion of our risks. However, not all potential risks arising from our operations are insurable or are insured by us as a result of lack of availability, high premiums or other reasons. Enbridge self-insures a significant portion of certain risks through our wholly-owned captive insurance subsidiaries, and Enbridge’s insurance coverage is subject to terms and conditions, exclusions and large deductibles or self-insured retentions, which may reduce or eliminate coverage in certain circumstances.

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

A significant self-insured loss, uninsured loss, a loss significantly exceeding the limits of our insurance policies, a significant delay in the payment of a major insurance claim, or the failure to renew insurance policies on similar or favorable terms, could materially and adversely affect our business, financial condition and results of operations.

Our business is exposed to changes in market prices, including interest rates and foreign exchange rates. Our risk management policies cannot eliminate all risks and may result in material financial losses. In addition, any non-compliance with our risk management policies could adversely affect our business, operations or financial results.

Our use of debt financing exposes us to changes in interest rates on both future fixed rate debt issuances and floating rate debt. While our financial results are denominated in Canadian dollars, many of our businesses have foreign currency revenues or expenses, particularly the US dollar. Changes in interest rates and foreign exchange rates could materially impact our financial results.

We use financial derivatives to manage risks associated with changes in foreign exchange rates, interest rates, commodity prices, power prices and our share price, to reduce the volatility of our cash flows. Based on our risk management policies, substantially all of our financial derivatives are associated with an underlying asset, liability and/or forecasted transaction and are not intended for speculative purposes.

These policies cannot, however, eliminate all risk, including unauthorized trading. Although this activity is monitored independently by our risk management function, we can provide no assurance that we will detect and prevent all unauthorized trading and other violations, particularly if deception, collusion or other intentional misconduct is involved, and any such violations could adversely affect our business, operations or financial results.

To the extent that we hedge our exposure to market prices, we will forego the benefits we would otherwise experience if these were to change in our favor. In addition, hedging activities can result in losses that might be material to our financial condition, results of operations and cash flows. Such losses have occurred in the past and could occur in the future. See Part II, *Item 7A. Quantitative and Qualitative Disclosures about Market Risk* and *Item 8. Financial Statements and Supplementary Data* for a discussion of our derivative instruments and related hedging activities.

We rely on access to short-term and long-term capital markets to finance capital requirements and support liquidity needs. Cost effective access to those markets can be affected, particularly if we or our rated subsidiaries are unable to maintain an investment-grade credit rating.
A significant portion of our consolidated asset base is financed with debt. The maturity and repayment profile of debt used to finance investments often does not correlate to cash flows from assets. Accordingly, we rely on access to both short-term and long-term capital markets as a source of liquidity for capital requirements not satisfied by cash flows from operations and to refinance investments originally financed with debt. Our senior unsecured long-term debt is currently rated investment-grade by various rating agencies. If the rating agencies were to rate us or our rated subsidiaries below investment-grade, our borrowing costs could increase, potentially significantly. Consequently, we could be required to pay a higher interest rate in future financings and our potential pool of investors and funding sources could decrease.

We maintain revolving credit facilities at various entities to backstop commercial paper programs, for borrowings and for providing letters of credit. These facilities typically include financial covenants and failure to maintain these covenants at a particular entity could preclude that entity from accessing the credit facility, which could impact liquidity. If our short-term debt rating were to be downgraded, access to the commercial paper market could be significantly limited. Although this would not affect our ability to draw under our credit facilities, borrowing costs could be significantly higher.

If we are not able to access capital at competitive rates or at all, our ability to finance operations and implement our strategy may be affected. An inability to access capital on favorable terms or at all may limit our ability to pursue enhancements or acquisitions that we may otherwise rely on for future growth or to refinance our existing indebtedness. Any downgrade or other event negatively affecting the credit ratings of our subsidiaries could make their costs of borrowing higher or access to funding sources more limited, which in turn could increase our need to provide liquidity in the form of capital contributions or loans to such subsidiaries, thus reducing the liquidity and borrowing availability of the consolidated group.

Our Liquids Pipelines growth rate and results may be indirectly affected by commodity prices.
Wide commodity price basis between Western Canada and global tidewater markets has negatively impacted producer netbacks and margins in the past that largely resulted from pipeline infrastructure takeaway capacity from producing regions in Western Canada and North Dakota, which are operating at capacity. A protracted long-term outlook for low crude oil prices could result in delay or cancellation of future projects.

The tight conventional oil plays of Western Canada, the Permian Basin, and the Bakken region of North Dakota, have short cycle break-even time horizons, typically less than 24 months, and high decline rates that can be managed through active hedging programs and are positioned to react quickly to market signals. Accordingly, during periods of comparatively low prices, drilling programs, unsupported by hedging programs, may be reduced, and as such, supply growth from tight oil basins may be lower, which could impact volumes on our pipeline systems.

Crude oil marketing generates margin by capitalizing on quality, time and location differentials when opportunities arise. Changing market conditions that impact the prices at which we buy and sell commodities have in the past limited margin opportunities and impeded our ability to cover capacity commitments and could do so again in the future. Other market conditions, such as backwardation, have likewise limited margin opportunities.

Our Gas Transmission results may be adversely affected by commodity price volatility.
Within our US Midstream assets, we hold a 13.2% effective economic interest in DCP, which is engaged in the businesses of gathering, treating, processing and selling natural gas and natural gas liquids. In addition, we own Tomorrow RNG, which operates landfill gas-to-RNG production facilities and Aitken Creek Gas Storage Facility, which operates an underground natural gas storage facility. The financial results of these businesses are directly and indirectly impacted by changes in commodity prices. To a lesser degree, the financial results of our Gas Transmission business is subject to fluctuation in power prices, which impact electric power costs associated with operating some of our compressor stations.

We are exposed to the credit risk of our customers, counterparties, and vendors.
We are exposed to the credit risk of multiple parties in the ordinary course of our business. Generally, our customers are rated investment-grade, are otherwise considered creditworthy, or provide us with security to satisfy credit concerns. However, we cannot predict to what extent our business would be impacted by deteriorating conditions in the economy, including possible declines in the creditworthiness of our customers, vendors, or counterparties. It is possible that payment or performance defaults from these entities, if significant, could adversely affect our earnings and cash flows.

Our business requires the retention and recruitment of a skilled and diverse workforce, and difficulties in recruiting and retaining our workforce could result in a failure to implement our business plans.
Our operations and management require the retention and recruitment of a skilled and diverse workforce, including engineers, technical personnel, other professionals and executive officers and senior management. Enbridge and our affiliates compete with other companies in the energy industry, and for some jobs the broader labor market, for this skilled workforce. If we are unable to retain current employees and/or recruit new employees of comparable knowledge and experience, our business could be negatively impacted. In addition, we could experience increased costs to retain and recruit these professionals.

RISKS RELATED TO GOVERNMENT REGULATION AND LEGAL RISKS

Many of our operations are regulated and failure to secure timely regulatory approval for our proposed projects, or loss of required approvals for our existing operations, could have a negative impact on our business, operations or financial results.
The nature and degree of regulation and legislation affecting permitting and environmental review for energy infrastructure companies in Canada and the US continues to evolve. In addition, within the US and in Canada, energy companies continue to face opposition from anti-energy/anti-pipeline activists, environmental groups, politicians and other stakeholders concerned with the safety of energy infrastructure and its potential environmental effects.

In the US, the EPA released rules to reduce methane emissions from the oil and gas sector, standards for reducing emissions from fossil fuel fired power plants, and rules to streamline the process for states and tribes to assume authority over the *Clean Water Act*'s section 404 permitting program for discharges of dredge and fill material. The Council for Environmental Quality (CEQ) issued its Phase 2 rule concerning analyses under the *National Environmental Policy Act* (NEPA), that may significantly change environmental scope and cost assessments for energy projects. The FERC has focused on the relationship between natural gas and electric power generation, particularly in connection with reliability issues during severe weather events. PHMSA issued rules updating requirements for sustainable and safe pipeline operation. Many regulations are being challenged in the courts, including the ability of the CEQ to promulgate regulations applicable to other federal agencies, and some have been overturned by reviewing courts. The new US administration may take further action to modify or reverse regulations that were promulgated by the current US administration.

In Canada, the Supreme Court of Canada issued a decision on the federal *Impact Assessment Act* (IAA), finding that it is largely outside of the federal Parliament's authority and that the IAA should focus more narrowly on effects within federal jurisdiction. The federal government amended the IAA in response to this decision; however, the scope and application of federal review of intraprovincial pipeline projects remains unclear. In November 2024, the Government of Alberta has again referred the issue to the Alberta Court of Appeal for hearing, to determine whether the IAA, as amended, is unconstitutional. As a result, the uncertainty for pipeline and other energy infrastructure projects in Canada is ongoing.

These actions could adversely impact permitting of a wide range of energy projects. We may not be able to obtain or maintain all required regulatory approvals for our operating assets or development projects. If there is a significant delay in obtaining any required regulatory approvals, if we fail to obtain or comply with them, or if laws or regulations change or are administered in a more stringent manner, the operations of existing facilities or the development of new facilities could be prevented, delayed or become subject to additional costs.

Our operations are subject to numerous environmental laws, regulations, and rules, including those relating to climate change, GHG emissions, climate-related disclosure, and anti-greenwashing, compliance with which may require significant capital expenditures, increase our cost of operations, affect or limit our business plans, expose us to environmental liabilities or litigation, and affect our reputation and relationships with stakeholders.

We are subject to numerous environmental laws and regulations affecting many aspects of our operations, including, but not limited to, air emissions, climate change, water, soil, land management, waste, hazardous substances, wildlife and protected species, biodiversity, noise, emergency response, and pollution. We are also subject to new and evolving laws, regulations and rules related to ESG and sustainability-related disclosure, including climate-related disclosure, and anti-greenwashing provisions, including recent amendments to Canadian competition legislation, which simultaneously increase stakeholder expectations to report environmental and climate-related information and also substantiate such information in accordance with standards that are still developing and evolving, and which may, in some cases conflict. Our exposure to these risks could result in adverse impacts to our reputation and relationships with stakeholders or increased costs, liabilities or litigation.

If we are unable to obtain or maintain all required environmental regulatory approvals and permits for our operating assets and projects, or if there is a delay in obtaining any required environmental regulatory approvals or permits, the operation of existing facilities or the development of new facilities could be prevented, delayed, or become subject to additional costs. Failure to comply with environmental laws, regulations, and rules may result in the imposition of civil or criminal fines, penalties and injunctive measures affecting our operating assets. We expect that changes in environmental laws, regulations, and rules, including those related to climate change, GHG emissions, climate-related disclosure, and anti-greenwashing, could result in a material increase in our cost of compliance with such laws and regulations, such as costs to monitor and report our emissions, install new emission controls to reduce emissions, and third-party substantiation, verification or assurance of our environmental data, the costs of which we may not be able to recover.

Our operations are subject to operational regulation and other requirements, including compliance with easements and other land tenure documents, and failure to comply with applicable regulations and other requirements could have a negative impact on our reputation, business, operations or financial results.

Operational risks relate to compliance with applicable operational rules and regulations mandated by governments, applicable regulatory authorities, or other requirements that may be found in easements, permits, or other agreements that provide a legal basis for our operations, breaches of which could result in fines, penalties, awards of damages, operational restrictions or shutdowns, and an overall increase in operating and compliance costs.

We do not own all of the land on which our pipelines, facilities and other assets are located, and we obtain the right to construct and operate our pipelines and other assets from third parties or government entities. In addition, some of our pipelines, facilities and other assets cross Indigenous lands pursuant to rights-of-way or other land tenure interests. Our loss of these rights, including through our inability to renew them as they expire, could have an adverse effect on our reputation, operations and financial results. We have experienced litigation in relation to Line 5 and other easements. Refer to Part II. *Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - Legal and Other Updates*.

Regulatory scrutiny of our assets and operations has the potential to increase operating costs or limit future projects. Regulatory enforcement actions issued by regulators for non-compliance can increase operating costs and negatively impact reputation. Potential regulatory changes and legal challenges could have an impact on our future earnings from operations and the cost related to the construction of new projects. Future actions of regulators may differ from current expectations, or future legislative changes may impact the regulatory environments in which we operate. While we seek to mitigate operational regulation risk by actively monitoring and consulting on potential regulatory requirement changes with the respective regulators directly, or through industry associations, and by developing response plans to regulatory changes or enforcement actions, such mitigation efforts may be ineffective or insufficient. While we believe the safe and reliable operation of our assets and adherence to existing regulations is the best approach to managing operational regulatory risk, the potential remains for regulators or other government officials to make unilateral decisions that could disrupt our operations or have an adverse financial impact on us.

Our operations are subject to economic regulation and failure to secure regulatory approval for our proposed or existing commercial arrangements could have a negative impact on our business, operations or financial results.

Our Liquids Pipelines, Gas Transmission, and Gas Distribution and Storage assets face economic regulation risk. Broadly defined, economic regulation risk is the risk that governments or regulatory agencies change or reject proposed or existing commercial arrangements or policies, including permits and regulatory approvals for both new and existing projects or agreements, upon which future and current operations are dependent. Our Mainline System, other liquids pipelines, gas transmission and distribution assets are subject to the actions of various regulators, including the CER, the FERC, the OEB, the Ohio Commission, the Utah Commission, the Wyoming Commission, the Idaho Commission, and the North Carolina Commission, with respect to the rates, tariffs, and tolls for these assets. The changing or rejection of commercial arrangements, including decisions by regulators on the applicable permits and tariff structure or changes in interpretations of existing regulations by courts or regulators, has had in the past, and could in the future have an adverse effect on our revenues and earnings.

Our Renewable Power Generation assets in Canada and the US are subject to directives, regulations, and policies of federal, provincial and state governments. These measures are variable and can change as a result of, among other things, tax rate changes and a change in the government, which can have a negative impact on our commercial arrangements.

Our Renewable Power Generation assets in Europe (France, Germany and the UK) are also subject to the directives, regulations and policies established and enforced by the EU and the UK government. These measures are variable and can include price controls, caps and demand reduction goals, all of which can have a negative impact on our revenues and earnings.

We are subject to changes in our tax rates, the adoption of new US, Canadian or international tax legislation or exposure to additional tax liabilities.
We are subject to taxes in the US, Canada and numerous foreign jurisdictions. Due to economic and political conditions, tax rates in various jurisdictions may be subject to significant change. Our effective tax rates could be affected by changes in the mix of earnings in countries with differing statutory tax rates, changes in the valuation of deferred tax assets and liabilities, or changes in tax laws or their interpretation.

We are also subject to the examination of our tax returns and other tax matters by the US Internal Revenue Service, the Canada Revenue Agency and other tax authorities and governmental bodies. We regularly assess the likelihood of an adverse outcome resulting from these examinations to determine the adequacy of our provision for taxes. There can be no assurance as to the outcome of these examinations. If our effective tax rates were to increase, particularly in the US or Canada, or if the ultimate determination of our taxes owed is for an amount in excess of amounts previously accrued, our financial condition and operating results could be materially adversely affected.

We are involved in numerous legal proceedings, the outcomes of which are uncertain, and resolutions adverse to us could adversely affect our financial results and reputation.
We are subject to numerous legal proceedings related to our business and operations. In recent years, there has been an increase in climate-related regulatory action and litigation, including against companies involved in the energy industry. There is no assurance that we will not be impacted by such regulatory action, litigation, or other legal proceedings. By its nature, litigation is subject to many uncertainties, and we cannot predict the outcome of individual matters with assurance. It is reasonably possible that the final resolution of some of the matters in which we are involved or new matters could require additional expenditures, in excess of established reserves, over an extended period of time and in a range of amounts that could adversely affect our financial results or adversely affect our reputation. Refer to Part II. *Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - Legal and Other Updates* for a discussion of certain legal proceedings with recent developments.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 1C. CYBERSECURITY

Cybersecurity risk management, strategy and governance
Oversight of cybersecurity is integrated into the responsibilities of the Board and its committees. The Board is responsible for identifying and understanding Enbridge’s principal risks and ensuring that appropriate systems are implemented to monitor, manage and mitigate those risks. The committees of the Board have oversight over risks within their respective mandates.

The Audit, Finance and Risk Committee (AFRC) provides primary oversight of cybersecurity matters, including with respect to financial risk and controls, integrity of financial data and public disclosures, and security of the cyber landscape across data and digital. Management provides quarterly cybersecurity reports to the AFRC and the Board and also reports to the Safety and Reliability Committee, as deemed necessary, on cybersecurity issues related to safety, reliability and operations.

Each year, management prepares and provides to the Board and its committees a corporate risk assessment (CRA), which analyzes and prioritizes enterprise-wide risks, highlighting top risks and trends (including cybersecurity). The annual CRA is an integrated enterprise-wide process which engages each part of our business to assess and rank risks based on impact and probability. We strive to ensure that mitigation measures are appropriately designed, prioritized and resourced. The CRA report is reviewed by the Board committees with responsibility for the risk categories relevant to their mandate and is provided to the Board, which coordinates Enbridge's overall risk management approach. Complementary to the CRA, management prepares and provides to the Safety and Reliability Committee an annual top operational risk report that highlights the highest consequence operational risks across Enbridge and includes further detail on the risks and their treatment. This information helps inform the Board about the potential impact of top operational risks and of treatments in place to manage those risks.

Cybersecurity has been identified as a top risk, as attacks against participants in our industry have continued to increase in sophistication and frequency over the years. Although we devote significant resources and security measures to prevent unwanted intrusions and to protect our systems and data, we (and our third-party vendors) have experienced, and expect to continue to experience, cyber attacks of varying degrees in the conduct of our business, including, for example, denial of service attacks. Cybersecurity risk is described in *Item 1A. Risk Factors.*

Enbridge’s management is responsible for the implementation of risk management strategies and monitoring performance. The technology and information services (TIS) function is centralized under the Senior Vice President & Chief Information Officer (CIO). We also engage independent third parties to assess our cybersecurity program, track their recommendations, and use those to further improve the program. Reporting to the CIO is the Chief Information Security Officer who is in charge of our cybersecurity program and oversees the 24x7x365 Security Operations Center (SOC).

We conduct continuous assessments of our cybersecurity standards, perform regular tests of our ability to respond and recover, and monitor for potential threats. To further mitigate threats, we collaborate with governments and regulatory agencies and take part in external events to learn and share. Our workforce participates in regular security awareness training, including exercises to build capabilities to identify and report suspect phishing emails to our SOC. In the last year, we continued to expand the cybersecurity training and simulated testing we administer to high-risk groups within the organization. A tailored cybersecurity training course has been implemented for team members in operational technology roles, and we have increased the frequency of phishing simulation tests.

We have a cybersecurity third-party risk management program, which is an evolving, cross-functional program to help assess and mitigate risks from third-party vendors and other service providers. Our cybersecurity team also uses several layers of defense and protection technologies, cybersecurity experts, and automated alerting and response mechanisms to reduce risk to Enbridge.
Although cybersecurity risks have not materially affected us, including our business strategy, results of operations or financial condition, to date, we have experienced an increasing number of cybersecurity threats in recent years. For more information about the cybersecurity risks we face, see the risk factor entitled "*Cyber attacks and other cybersecurity incidents pose threats to our technology systems and could materially adversely affect our business, operations, reputation or financial results."* in *Item 1A. Risk Factors.*

ITEM 2. PROPERTIES

Descriptions of our properties and maps depicting the locations of our liquids, natural gas, and renewable power systems are included in Part I. *Item 1. Business*.

In general, our systems are located on land owned by others and are operated under easements and rights-of-way, licenses, leases or permits that have been granted by private landowners, Indigenous communities, public authorities, railways or public utilities. Our liquids pipeline systems have pumping stations, tanks, terminals and certain other facilities that are located on land that is owned by us and/or used by us under easements, licenses, leases or permits. Additionally, our natural gas pipeline systems have natural gas compressor stations, the vast majority of which are located on land that is owned by us. The remainder of these compressor stations and other assets, such as meter and valve stations, and underground gas storage fields, are used by us under easements, leases or permits.

Titles to Enbridge owned properties or affiliate entities may be subject to encumbrances in some cases. We believe that none of these burdens should materially detract from the value of these properties or materially interfere with their use in the operation of our business.

ITEM 3. LEGAL PROCEEDINGS

We are involved in various legal and regulatory actions and proceedings which arise in the ordinary course of business. 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. Refer to Part II. *Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - Legal and Other Updates* for discussion of certain legal proceedings with recent developments.

SEC regulations require the disclosure of any proceeding under environmental laws to which a governmental authority is a party unless the registrant reasonably believes it will not result in monetary sanctions over a certain threshold. Given the size of our operations, we have elected to use a threshold of US$1 million for the purposes of determining proceedings requiring disclosure. We have no such proceedings to disclose in this annual report.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Common Stock

Enbridge common stock is traded on the TSX and NYSE under the symbol ENB. As at February 7, 2025, there were 71,231 registered shareholders of record of Enbridge common stock. A substantially greater number of holders of Enbridge common stock are beneficial holders, whose shares are held by banks, brokers and other financial institutions.

Securities Authorized for Issuance Under Equity Compensation Plans

The information required by this Item will be contained in our Form 10-K/A, which will be filed no later than 120 days after December 31, 2024.

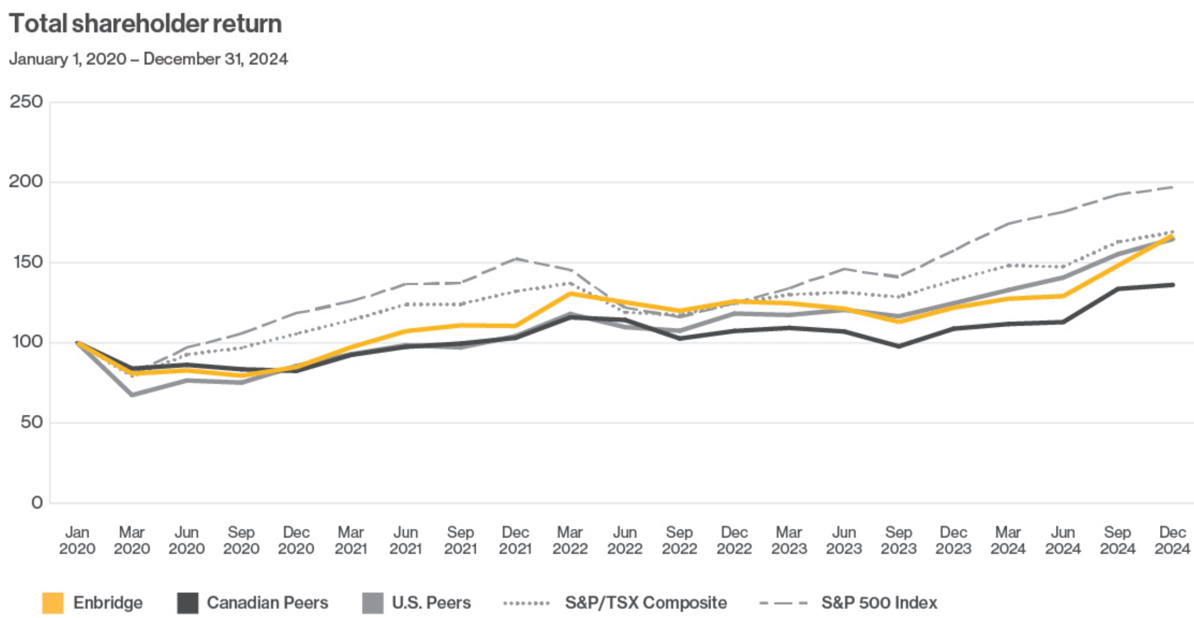
Recent Sales of Unregistered Equity Securities

None.

Issuer Purchases of Equity Securities

None.

Total Shareholder Return
The following graph reflects the comparative changes in the value from January 1, 2020 through December 31, 2024 of $100 invested in (1) Enbridge Inc.'s common shares traded on the TSX, (2) the S&P/TSX Composite index, (3) the S&P 500 index, (4) our US peer group (comprising, by stock symbols, CNP, D, DTE, DUK, EPD, ET, KMI, NEE, NI, OKE, PAA, PCG, SO, SRE and WMB) and (5) our Canadian peer group (comprising, by stock symbols, CU, FTS, PPL and TRP). The amounts included in the table were calculated assuming the reinvestment of dividends.



	January 1,	December 31,				
	2020	2020	2021	2022	2023	2024
Enbridge Inc.	100.00	84.81	110.46	125.81	121.84	167.00
S&P/TSX Composite	100.00	105.60	132.10	124.38	138.99	169.09
S&P 500 Index	100.00	118.40	152.39	124.79	157.59	197.02
US Peers[1]	100.00	85.54	104.13	118.20	124.62	164.67
Canadian Peers	100.00	82.44	103.04	107.34	108.76	136.07

1 For the purpose of the graph, it was assumed that CAD:US dollar conversion ratio remained at 1:1 for the years presented.

ITEM 6. [Reserved]

None.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

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 2024 and 2023 items and year-over-year comparisons between 2024 and 2023. For discussion of 2022 items and year-over-year comparisons between 2023 and 2022, 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, 2023.

RECENT DEVELOPMENTS

MAINLINE TOLLING AGREEMENT

The Mainline Tolling Settlement (MTS) is a negotiated settlement with a term of seven and a half years through the end of 2028 that covers both the Canadian and US portions of the Mainline, except for Lines 8 and 9 which are tolled on a separate basis. Enbridge Inc. (Enbridge) filed an application with the Canadian Energy Regulator (CER) for approval of the MTS on December 15, 2023 and the CER issued an order on March 4, 2024 approving Enbridge’s application as filed. Refer to Part I. *Item I. Business - Business Segments - Liquids Pipelines - Tolling Framework* for detailed terms of the MTS.

ACQUISITIONS

US Gas Utilities

On September 5, 2023, Enbridge entered into three separate definitive agreements with Dominion Energy, Inc. to acquire 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).

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

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

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

The Acquisitions further diversify, and are complementary to, our existing gas distribution operations.

Joint Venture with WhiteWater/I Squared and MPLX

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

- a 100% interest in the Whistler Pipeline, a 450-mile intrastate pipeline transporting natural gas from the Waha Header in the Permian Basin to Agua Dulce, Texas;
- a 100% interest in the Rio Bravo Pipeline project, two new parallel 137-mile pipelines transporting natural gas from the Agua Dulce supply area to NextDecade's Rio Grande LNG project in Brownsville, Texas;
- a 70% interest in the ADCC Pipeline, a new 40-mile pipeline which was placed into service in July 2024 and is designed to transport 1.7 billion cubic feet per day (bcf/d) of natural gas from the terminus of the Whistler Pipeline in Agua Dulce, Texas to Cheniere's Corpus Christi LNG export facility; and
- a 50% interest in Waha Gas Storage, a 2.0 bcf gas storage cavern facility connecting to key Permian egress pipelines including the Whistler Pipeline.

In connection with the formation of the Whistler Parent JV, we contributed our 100% interest in the Rio Bravo Pipeline project and $487 million (US$357 million) of cash to the Whistler Parent JV. In addition to our 19.0% equity interest in the Whistler Parent JV, we received a special equity interest in the Whistler Parent JV which provides for a 25.0% economic interest in the Rio Bravo Pipeline project. This interest is subject to certain redemption rights held by Whitewater/I Squared and MPLX. After the closing on May 29, 2024, we accrued for our share of the post-closing mandatory capital expenditures of approximately US$150 million for the Rio Bravo Pipeline project. Additional capital expenditures to complete the Rio Bravo Pipeline project will be proportionate to our economic interest.

Acquisition of Renewable Natural Gas (RNG) Facilities

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

ASSET MONETIZATION

Disposition of Alliance Pipeline and Aux Sable Interests

On April 1, 2024, we closed the sale of our 50.0% interest in the Alliance Pipeline, our interest in Aux Sable (including a 42.7% interest in Aux Sable Midstream LLC and Aux Sable Liquid Products L.P., and a 50.0% interest in Aux Sable Canada LP) and our interest in NRGreen Power Limited Partnership (NRGreen) to Pembina Pipeline Corporation (Pembina) for $3.1 billion, including $327 million of non-recourse debt. A gain on disposal of $1.1 billion before tax, which is net of $1.0 billion of the goodwill from our Gas Transmission segment allocated to the disposal group, is included in Gain on disposition of equity investments in the Consolidated Statements of Earnings for the year ended December 31, 2024.

GAS TRANSMISSION RATE PROCEEDINGS

Texas Eastern

In May 2024, Texas Eastern Transmission, LP (Texas Eastern) reached a negotiated settlement with customers to increase rates starting October 1, 2024 with additional increases on January 1, 2026. Texas Eastern filed a Stipulation and Agreement with the Federal Energy Regulatory Commission (FERC) on June 3, 2024 and received approval on July 31, 2024 from the FERC of its uncontested settlement with customers.

Algonquin

Algonquin Gas Transmission, LLC (Algonquin) filed a rate case on May 30, 2024. On June 28, 2024, the FERC issued an order accepting and suspending tariff records, subject to refund, conditions, and establishing hearing procedures. In December 2024, Algonquin reached a settlement in principle with customers which will be filed for FERC approval in the first quarter 2025. If approved, rates will be effective December 1, 2024.

Maritimes & Northeast Pipeline

Maritimes & Northeast Pipeline (M&N) US filed a rate case on May 30, 2024. On June 27, 2024, the FERC issued an order accepting and suspending tariff records, subject to refund, conditions, and establishing hearing procedures. In December 2024, M&N US reached a settlement in principle with customers which will be filed for FERC approval in the first quarter 2025. If approved, rates will be effective January 1, 2025.

GAS DISTRIBUTION AND STORAGE RATE APPLICATIONS

Incentive Regulation Rate Application

In October 2022, Enbridge Gas Inc. (Enbridge Gas Ontario) filed its application with the Ontario Energy Board (OEB) to establish a 2024 through 2028 Incentive Regulation (IR) rate setting framework. The application initially sought approval in two phases to establish 2024 base rates (Phase 1) on a cost-of-service basis and to establish a price cap rate setting mechanism (Phase 2) to be used for the remainder of the IR term (2025-2028). A third phase (Phase 3) has been established with the OEB as part of the Phase 1 Partial Settlement Proposal (Phase 1 Settlement). Phase 3 will address cost allocation and the harmonization of rates and rate classes between legacy rate zones, and is anticipated to be completed in 2025.

In August 2023, the OEB approved the Phase 1 Settlement and in December 2023, the OEB issued its Decision and Order on the remaining unsettled items in Phase 1 (Phase 1 Decision). These decisions include the following findings or orders:

- energy transition risk requires us to carry out a risk assessment to consider further risk mitigation measures in three areas: system access and expansion capital spending, system renewal capital spending and depreciation policy;
- all new small volume customers wishing to connect to natural gas are to pay their full connection costs as an upfront charge (the revenue horizon was set to zero years), rather than through rates over time effective January 2025;
- approval of a harmonized depreciation methodology that reduced the amount of depreciation sought and adjusted asset lives including extensions of service life for certain asset classes;
- the removal of $84 million of undepreciated integration capital costs from 2024 rate base; and
- an increase in equity thickness from 36% to 38% effective 2024.

Enbridge Gas Ontario filed a Notice of Appeal with the Ontario Divisional Court in January 2024 regarding various aspects of the Phase 1 Decision and subsequently filed an amended Notice of Appeal in December 2024 (Amended Appeal). The Amended Appeal focused on two aspects of the Phase 1 Decision: asset class average useful lives for depreciation purposes, and equity thickness. In January 2024, Enbridge Gas Ontario filed a Notice of Motion with the OEB requesting the OEB to review and vary the Phase 1 Decision which was subsequently amended in May 2024 (Amended Motion). The Amended Motion focused on two aspects of the Phase 1 Decision: asset class average useful lives for depreciation purposes, and the recoverability of integration capital. In October 2024, the OEB issued a decision on the Amended Motion and determined that only the issue of integration capital met the threshold to warrant a review. We are currently awaiting an OEB decision on the issue of integration capital.

In May 2024, Bill 165, the *Keeping Energy Costs Down Act,* received royal assent, giving the Government of Ontario time-limited authority to set the revenue horizon for small volume customers, effectively reversing that aspect of the OEB's Phase 1 Decision. Regulations are now in place setting the revenue horizon for new customer connections to 40 years.

In November 2024, the OEB issued its Decision approving the Phase 2 Partial Settlement Proposal (Phase 2 Settlement). The Phase 2 Settlement establishes a price cap IR rate setting mechanism to be used for establishing rates for 2025 – 2028. The price cap mechanism will establish new rates each year through an annual base rate adjustment to migrate an incremental $50 million in capitalized overheads to operating and maintenance costs, annual base rate escalation at inflation less a 0.28% productivity factor, annual updates for certain costs to be passed through to customers, and where applicable, it will provide for the recovery of material unexpected events and discrete incremental capital investments beyond those that can be funded through base rates. The price cap mechanism includes the continuation and establishment of certain deferral and variance accounts, as well as an earnings sharing mechanism that requires Enbridge Gas Ontario to share equally with customers any earnings in excess of 100 basis points over the allowed return on equity (ROE), and 90% of any earnings in excess of 300 basis points over the allowed ROE. Issues not addressed as part of the Phase 2 Settlement proceeded to hearing in December 2024 and a decision is expected in the second quarter of 2025.

Enbridge Gas Ohio
In October 2023, Enbridge Gas Ohio filed its base rate case and schedules with the Ohio Commission. Enbridge Gas Ohio proposed a non-fuel, base rate annual revenue increase of $212 million, projected 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. The proposed rates would have provided for an ROE of 10.40% compared to the currently authorized ROE of 10.38%. In addition, Enbridge Gas Ohio requested approval for an alternative rate plan for the continuation and modification of certain programs, including Pipeline Infrastructure Replacement and Capital Expenditure Program. On December 18, 2024, Enbridge Gas Ohio filed a Notice of Intent to Modify Filed Positions. The Notice of Intent indicated a willingness to accept a reduced annual revenue requirement increase (from $212 million to $60 million) and, if the reduced position were adopted, to forgo filing a new base rate case until October 31, 2027. The hearing began on January 13, 2025, and remains underway.

FINANCING UPDATE
We completed long-term debt issuances totaling US$5.7 billion and $1.8 billion during the year ended December 31, 2024.

On the March 8, 2024 call date, we redeemed at par all of the outstanding US$700 million three-year callable, 5.97% senior notes that carried an original maturity date in March 2026.

During our annual renewal process, we renewed and extended approximately $17.6 billion of our credit facilities with maturities ranging from 2025-2029. We also increased our letter of credit facilities by approximately $346 million and entered into new term loans with maturities ranging from 2029-2049 totaling approximately $542 million.

On May 15, 2024, we established an at-the-market equity issuance program (ATM Program) which provided us with additional flexibility to fund the Acquisitions. From May 15, 2024 to July 31, 2024, 51,298,629 common shares were issued on Canadian and US exchanges at average prices of CAD$48.72 and US$35.77 per common share for aggregate gross proceeds of $2.50 billion. On August 1, 2024, we terminated the ATM Program.

On September 8, 2023, we closed a public offering of 102,913,500 common shares at a price of $44.70 per share for gross proceeds of $4.6 billion which were also used to finance a portion of the aggregate cash consideration payable for the Acquisitions discussed in Note 6 - Acquisitions and Dispositions.

Our 2024 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, 2024, after adjusting for the impact of floating-to-fixed interest rate swap hedges, less than 5% 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.

RESULTS OF OPERATIONS

Year ended December 31,	2024	2023	2022
(millions of Canadian dollars, except per share amounts)			
Segment earnings/(loss) before interest, income taxes and depreciation and amortization[1]			
Liquids Pipelines	**9,531**	9,383	7,941
Gas Transmission	**5,656**	4,264	3,126
Gas Distribution and Storage	**2,869**	1,592	1,827
Renewable Power Generation	**733**	149	262
Eliminations and Other	**(1,904)**	916	(1,118)
Earnings before interest, income taxes and depreciation and amortization[1]	**16,885**	16,304	12,038
Depreciation and amortization	**(5,167)**	(4,613)	(4,317)
Interest expense	**(4,419)**	(3,812)	(3,179)
Income tax expense	**(1,668)**	(1,821)	(1,604)
(Earnings)/loss attributable to noncontrolling interests and redeemable noncontrolling interests	**(190)**	133	65
Preference share dividends	**(388)**	(352)	(414)
Earnings attributable to common shareholders	**5,053**	5,839	2,589
Earnings per common share attributable to common shareholders	**2.34**	2.84	1.28
Diluted earnings per common share attributable to common shareholders	**2.34**	2.84	1.28

1 Non-GAAP financial measures.

EARNINGS ATTRIBUTABLE TO COMMON SHAREHOLDERS

Year ended December 31, 2024 compared with year ended December 31, 2023
Earnings attributable to common shareholders decreased by $1.1 billion due to certain infrequent or other non-operating factors, primarily explained by the following:

- a non-cash, net unrealized loss of $2.1 billion ($1.6 billion after-tax) in 2024, compared with a net unrealized gain of $1.2 billion ($911 million after-tax) in 2023, reflecting changes in the mark-to-market value of derivative financial instruments used to manage foreign exchange, interest rate, and commodity price risk;
- the absence in 2024 of a gain of $151 million ($129 million after-tax) net of a deferred tax adjustment of $69 million recognized as a result of the discontinuation of regulatory accounting for Southern Lights Pipeline;
- an asset impairment loss of $137 million ($103 million after-tax) related to the Big Sandy Pipeline;
- severance costs of $105 million ($79 million after-tax) as a result of a workforce reduction in February 2024;
- $137 million ($114 million after-tax) of integration and transaction costs incurred related to the Acquisitions in 2024, as compared to $31 million ($24 million after-tax) of transaction costs in 2023;
- the absence of the receipt of a litigation claim settlement of $68 million ($52 million after-tax); and
- an impairment loss of $55 million ($49 million after-tax) related to certain renewable assets.

The factors above were partially offset by:

- a gain on sale of $1.1 billion ($765 million after-tax) related to the disposition of interests in the Alliance Pipeline, Aux Sable and NRGreen;
- the absence in 2024 of:
  - a realized loss of $638 million ($479 million after-tax) due to termination of foreign exchange hedges, as foreign exchange risks inherent within the Competitive Tolling Settlement (CTS) framework are not present in the negotiated MTS;
  - an impairment of $281 million ($232 million after-tax) recognized to certain capital projects, capital costs and pension balances in the fourth quarter of 2023 as a result of the OEB's Phase 1 Decision;
  - a provision adjustment of $124 million ($95 million after-tax) related to a litigation matter;
  - an asset retirement loss of $86 million ($65 million after-tax) related to our Alberta Regional Oil Sands System; and
- a deferred tax recovery of $141 million in 2024 due to change in state apportionment as a result of the Acquisitions.

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 $294 million increase in earnings attributable to common shareholders is primarily explained by the following significant business factors:

- contributions from Enbridge Gas Ohio, Enbridge Gas Utah and Wexpro, and Enbridge Gas North Carolina, and higher distribution charges resulting from increases in customer base and higher demand in the contract market from Enbridge Gas Ontario in our Gas Distribution and Storage segment;
- higher contributions from our Gas Transmission segment primarily due to favorable contracting and lower operating costs in our US Gas Transmission assets, and acquisitions of Tres Palacios and Aitken Creek in 2023, Tomorrow RNG, and Whistler Parent JV in 2024;
- higher contributions from our Renewable Power Generation segment due to the generation of investment tax credits from our investment in Fox Squirrel Solar and the acquisition of an additional 24.45% interest in the Hohe See and Albatros Offshore Wind Facilities in November 2023;
- higher contributions from our Liquids Pipelines segment due to lower Mainline power costs and discontinuation of rate-regulated accounting of Southern Lights Pipeline as at December 31, 2023; and
- higher investment income in Eliminations and Other from the pre-funding of the Acquisitions and from our wholly-owned insurance subsidiaries; partially offset by
- full year of lower Mainline system tolls in our Liquids Pipelines segment as a result of revised tolls effective July 1, 2023 and lower Line 3 Replacement (L3R) surcharge;
- lower contributions from Alliance Pipeline and Aux Sable from our Gas Transmission segment due to the sale of our interest in these investments in April 2024;
- higher interest expense primarily due to higher average principal outstanding resulting from the Acquisitions;
- higher depreciation and amortization expense mainly driven by acquisitions we completed in 2023 and 2024, as mentioned above;
- higher income tax expense largely driven by higher earnings and higher US minimum tax; and
- higher realized foreign exchange loss on hedge settlements in Eliminations and Other in 2024.

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

Transportation and other services revenues of $19.7 billion, $19.2 billion and $17.9 billion for the years ended December 31, 2024, 2023 and 2022, 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 $6.8 billion, $5.4 billion and $6.2 billion for the years ended December 31, 2024, 2023 and 2022, 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 $27.0 billion, $19.0 billion and $29.2 billion for the years ended December 31, 2024, 2023 and 2022, 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,	**2024**	2023	2022
(millions of Canadian dollars)			
Earnings before interest, income taxes and depreciation and amortization	**9,531**	9,383	7,941

Year ended December 31, 2024 compared with year ended December 31, 2023
EBITDA was negatively impacted by $71 million due to certain infrequent or other non-operating factors, primarily explained by the following:

- a non-cash, net unrealized gain of $2 million in 2024, compared with a net unrealized gain of $615 million in 2023, reflecting net fair value gains and losses arising from changes in the mark-to-market value of derivative financial instruments used to manage foreign exchange and commodity price risks; and
- the absence in 2024 of both a gain of $151 million recognized as a result of Southern Lights' discontinuation of regulatory accounting and the receipt of a litigation claim settlement of $68 million, partially offset by
- the absence in 2024 of both a realized loss of $638 million due to termination of foreign exchange hedges, as foreign exchange risks inherent within the CTS framework are not present in the negotiated MTS and an asset retirement loss of $86 million related to our Alberta Regional Oil Sands System; and
- a net positive adjustment to crude oil inventory of $15 million in 2024, compared with a net negative adjustment of $16 million in 2023.

After taking into consideration the factors above, the remaining $219 million increase is primarily explained by the following significant business factors:

- lower Mainline power costs from operational efficiencies and lower Alberta mill rates;
- higher contributions from the Southern Lights Pipeline due primarily to the discontinuation of rate-regulated accounting as at December 31, 2023;
- higher contributions from the Gulf Coast and Mid-Continent System due primarily to higher volumes on the Flanagan South Pipeline driven by the open season commitments that commenced in the first quarter of 2024, and the Enbridge Ingleside Energy Center due to higher demand and new storage contracts that commenced in the second quarter of 2024; and
- the favorable effect of translating US dollar EBITDA at a higher average exchange rate in 2024, as compared to 2023, partially offset by
- full year of lower Mainline System tolls as a result of revised tolls effective July 1, 2023 and a lower L3R surcharge.

GAS TRANSMISSION

Year ended December 31,	**2024**	2023	2022
(millions of Canadian dollars)			
Earnings before interest, income taxes and depreciation and amortization	**5,656**	4,264	3,126

Year ended December 31, 2024 compared with year ended December 31, 2023
EBITDA was positively impacted by $1,008 million due to certain infrequent or other non-operating factors primarily explained by the following:

- a gain on sale of $1,063 million on the disposition of interests in the Alliance Pipeline and Aux Sable; and
- the absence in 2024 of both a negative provision adjustment of $124 million related to a litigation matter and an impairment loss of $82 million related to certain Offshore equity investments, partially offset by
- an asset impairment loss of $137 million related to the Big Sandy Pipeline;
- a non-cash, net unrealized loss of $3 million in 2024, compared with a net unrealized gain of $32 million in 2023, reflecting changes in the mark-to-market value of derivative financial instruments used to manage commodity price risk;
- a non-cash revaluation loss of $33 million to the gas inventory at Aitken Creek; and
- a loss of $29 million as a result of the contribution of our 100% interest in the Rio Bravo Pipeline project to the Whistler Parent JV.

After taking into consideration the factors above, we saw a $384 million increase, primarily explained by the following significant business factors:

- favorable contracting and lower operating costs on our US Gas Transmission assets;
- contributions from the acquisitions of Tres Palacios in the second quarter of 2023, Aitken Creek in the fourth quarter of 2023, Tomorrow RNG in the first quarter of 2024 and Whistler Parent JV in the second quarter of 2024; and
- the favorable effect of translating US dollar EBITDA at a higher average exchange rate in 2024, compared to the same period in 2023, partially offset by
- lower contributions from Alliance Pipeline and Aux Sable due to the sale of our interests in these investments in April 2024.

GAS DISTRIBUTION AND STORAGE

Year ended December 31,	**2024**	2023	2022
(millions of Canadian dollars)			
Earnings before interest, income taxes and depreciation and amortization	**2,869**	1,592	1,827

Year ended December 31, 2024 compared with year ended December 31, 2023
EBITDA was positively impacted by $281 million due to the absence in 2024 of an impairment of $281 million recognized to certain capital projects, capital costs and pension balances in the fourth quarter of 2023 as a result of the OEB's Phase 1 Decision.

After taking into consideration the factors above, the remaining $996 million increase is primarily explained by contributions from Enbridge Gas Ohio, Enbridge Gas Utah and Wexpro, and Enbridge Gas North Carolina since their acquisitions in 2024. In addition, the increase is also explained by:

- higher distribution charges resulting from increases in customer base and higher demand in the contract market at Enbridge Gas Ontario, partially offset by
- warmer than normal weather in 2024, when compared with the normal weather forecast embedded in rates, which negatively impacted Enbridge Gas Ontario 2024 EBITDA by approximately $58 million period over period.

RENEWABLE POWER GENERATION

Year ended December 31,	**2024**	2023	2022
(millions of Canadian dollars)			
Earnings before interest, income taxes and depreciation and amortization	**733**	149	262

Year ended December 31, 2024 compared with year ended December 31, 2023
EBITDA was positively impacted by $295 million due to certain infrequent or non-operating factors, primarily explained by:

- the absence in 2024 of an impairment loss of $261 million to Chapman Ranch wind facilities;
- a non-cash, net unrealized loss of $13 million in 2024, compared with a net unrealized loss of $72 million in 2023, reflecting changes in the mark-to-market value of derivative financial instruments used to manage foreign exchange and commodity price risks; and
- a gain on sale of $29 million related to disposition of our interest in NRGreen, partially offset by
- an impairment loss of $55 million related to certain assets.

After taking into consideration the positive factors above, the remaining $289 million increase is primarily explained by the following significant business factors:

- contributions from our investment in Fox Squirrel Solar as a result of the generation of investment tax credits;
- higher contribution from the Hohe See and Albatros Offshore Wind Facilities as a result of the November 2023 acquisition of an additional 24.45% interest in these facilities; and
- strong wind resources at European offshore wind facilities.

ELIMINATIONS AND OTHER

Year ended December 31,	**2024**	2023	2022
(millions of Canadian dollars)			
Earnings/(loss) before interest, income taxes and depreciation and amortization	**(1,904)**	916	(1,118)

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 subsidiaries. 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, 2024 compared with year ended December 31, 2023
EBITDA was negatively impacted by $3,098 billion due to certain infrequent or non-operating factors, primarily explained by:

- a non-cash, net unrealized loss of $2.2 billion in 2024, compared with a net unrealized gain of $688 million in 2023, reflecting changes in the mark-to-market value of derivative financial instruments used to manage foreign exchange and commodity price risks;
- severance costs of $105 million as a result of a workforce reduction in February 2024;
- $137 million of integration and transaction costs incurred related to the Acquisitions in 2024, as compared to $31 million of transaction costs in 2023; and
- a non-cash, net unrealized loss of $15 million in 2024, compared with a net unrealized gain of $35 million in 2023, reflecting changes in the mark-to-market value of equity fund investments held by our wholly-owned captive insurance subsidiaries.

After taking into consideration the non-operating factors above, we saw a $278 million increase in EBITDA that is primarily explained by:

- higher investment income from the pre-funding of the Acquisitions and from our wholly-owned captive insurance subsidiaries; and
- timing of certain operating and administrative cost recoveries from the business units, partially offset by
- higher realized foreign exchange loss on hedge settlements in 2024.

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)						
GAS TRANSMISSION						
1.	Texas Eastern Venice Extension[3]	100%	US$0.5 billion	US$423 million	In service	2024
2.	Texas Eastern Modernization	100%	US$0.4 billion	US$124 million	Under construction	2025 - 2026
3.	T-North Expansion (Aspen Point)	100%	$1.2 billion	$270 million	Pre-construction	2026
4.	Tennessee Ridgeline Expansion	100%	US$1.1 billion	US$217 million	Pre-construction	2026
5.	Woodfibre LNG[4]	30%	US$1.5 billion	US$649 million	Under construction	2027
6.	T-South Expansion (Sunrise)	100%	$4.0 billion	$190 million	Pre-construction	2028
7.	Canyon System Pipelines	100%	US$0.7 billion	US$5 million	Pre-construction	2029
GAS DISTRIBUTION AND STORAGE						
8.	Moriah Energy Center[5]	100%	US$0.6 billion	US$207 million	Under construction	2027
9.	T15 Reliability Project[5,6]	100%	US$0.7 billion	US$9 million	Pre-construction	2027-2028
RENEWABLE POWER GENERATION						
10.	Fox Squirrel Solar	50%	US$0.6 billion	US$541 million	In service	2024
11.	Sequoia Solar	100%	US$1.1 billion	US$420 million	Various stages	2025 - 2026
12.	Calvados Offshore Wind[7]	21.7%	$1.0 billion (€0.6 billion)	$426 million (€294 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, 2024.
3 Includes the US$37 million Gator Express Project placed into service in August 2023. Total estimated capital cost consists of the reversal and expansion of Texas Eastern's Line 40.
4 Our equity contribution is approximately US$0.9 billion, with the remainder financed through non-recourse project level debt. Capital cost estimates will be updated in 2025, at which point Enbridge's preferred return will be set.
5 Previously approved PSNC projects that were acquired by Enbridge through the Acquisitions.
6 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.
7 Our equity contribution 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 under Part I. *Item 1A. Risk Factors.*

The following commercially secured growth projects are currently in various stages of construction:

GAS TRANSMISSION

- **Texas Eastern Venice Extension Project** – A reversal and expansion of Texas Eastern’s Line 40 from its existing New Roads compressor station to a new delivery point with the proposed Gator Express pipeline just south of Texas Eastern’s Larose compressor station. The project is expected to deliver 1.5 bcf/d of natural gas to Venture Global Plaquemines LNG, LLC’s LNG export facility located in Plaquemines Parish, Louisiana and is underpinned by long-term take or pay contracts.

- **Texas Eastern Modernization** – This program is the modernization of compression facilities in Pennsylvania and New Jersey to increase safety and reliability and reduce associated greenhouse gas emissions at multiple sites on our Texas Eastern system. The program is expected to be completed in stages over a period of years beginning in 2024.

- **T-North Expansion (Aspen Point)** – An expansion of Westcoast Energy Inc.'s (Westcoast) British Columbia (BC) Pipeline in northern BC that includes pipeline looping, additional compressor units and other ancillary station modifications to support 535 million cubic feet per day (mmcf/d) of additional capacity. The expansion is to serve growing regional demand for natural gas and potential west coast LNG exports and will be underpinned by a cost-of-service commercial model with a target in-service date of 2026. T-North Expansion received regulatory approval from the CER in December 2024.

- **Tennessee Ridgeline Expansion** – The Tennessee Ridgeline Expansion project is an expansion of the East Tennessee Natural Gas (ETNG) 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 behind-the-meter solar array.

- **Woodfibre LNG Project** – Construction of liquefaction and floating storage facilities in Squamish, BC, and an expansion of the BC Pipeline System. Construction of the facilities is executed by our partner; Enbridge holds a non-controlling interest in this project. The project is expected to be placed into service in 2027.

- **T-South Expansion (Sunrise)** – An expansion of Westcoast's BC Pipeline's T-South section that includes pipeline looping, additional compressor units and other ancillary station modifications to support 300 mmcf/d of additional capacity. The 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, which is expected to come into service in 2027. The project is underpinned by a cost-of-service commercial model and is expected to be placed in service in 2028. We filed the regulatory application with the CER in May 2024.

- **Canyon System Pipelines** – The project includes the construction of two new offshore pipelines in the US Gulf Coast to deliver natural gas and crude oil from BP Exploration & Production Company's Kaskida offshore project. The development includes a new 24/26-inch oil pipeline which will connect to Shell Pipeline Company LP's Green Canyon 19 Platform, and a 12-inch gas pipeline connecting to Enbridge's Magnolia Gas Gathering System.

GAS DISTRIBUTION AND STORAGE

- **Moriah Energy Center** – Moriah Energy Center is an LNG facility that is under construction in Person County, North Carolina with 2 bcf storage capacity. The facility is required to ensure system reliability and address supply constraints due to customer growth and will be designed with trucking capabilities to support other LNG facilities. The construction started in first quarter of 2024 and is expected to achieve completion in 2027.

- **T-15 Reliability Project** – The 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 is expected to start construction in 2026 and to achieve two-phased project completion in 2027 and 2028.

RENEWABLE POWER GENERATION

- **Fox Squirrel Solar** – Fox Squirrel Solar is a fully contracted, ground-mounted solar facility in Ohio with expected installed capacity of approximately 577 megawatts (MW). All three phases of the project are currently in service. Project revenues are underpinned by a 20-year fixed price power purchase agreement (PPA).

- **Sequoia Solar Project** – Sequoia Solar Project is an 815-megawatt solar farm located approximately 150 miles west of Dallas, Texas. The two-phased project is expected to achieve project completion in 2025 and 2026. Project revenues are underpinned by long-term fixed price PPAs.

- **Calvados Offshore Wind Project** – Calvados is an offshore wind project located off the northwest coast of France that is expected to generate approximately 448 MW. Project revenues are underpinned by a 20-year fixed price PPA.

OTHER ANNOUNCED PROJECTS UNDER DEVELOPMENT

The following project has been announced by us, but has not yet met our criteria to be classified as commercially secured:

RENEWABLE POWER GENERATION
Seven Stars Energy Project
On June 24, 2024, Enbridge and Six Nations Energy Development LP, a newly-created consortium of Cowessess, George Gordon, Kahkewistahaw, Pasqua and White Bear First Nations, as well as Métis Nation-Saskatchewan, announced plans to advance development of a new wind energy project southeast of Weyburn, Saskatchewan. The Seven Stars Energy Project (the Project) is expected to produce 200 MW of wind power. It will be developed, constructed and operated by Enbridge.

Financial participation of the partners is expected to be supported, in part, by loan guarantees of up to $100 million from the Saskatchewan Indigenous Investment Finance Corporation. Our Indigenous partners have an opportunity to acquire equity ownership of at least 30% in the Project.

The Project is targeted to be operational in 2027, subject to finalizing commercial agreements, securing the necessary environmental and regulatory approvals, and meeting investment criteria.

We also have a portfolio of additional projects under development that have not yet progressed to the point of commercial securement.

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 and acquisitions 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 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 issuance and/or credit facility draws and the proceeds of capital market offerings to fund liabilities as they become due, finance capital expenditures and acquisitions, fund debt retirements and pay common and preference share dividends. We target maintaining sufficient liquidity through the use 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* and *Note 26 - Leases* for amounts outstanding at December 31, 2024, related to debt and leases, respectively.

Long-term contracts are contracts that we have signed for the purchase of services, pipe and other materials totaling $10.8 billion which are expected to be paid over the next five years. Remaining 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, service and product purchase obligations 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 ensure ready access to capital markets, subject to market conditions, through maintenance of shelf prospectuses that allow for issuance 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 US$5.7 billion and $1.8 billion in 2024:

Entity	Issuance date	Type of issuance	Amount
(in millions of Canadian dollars, unless stated otherwise)			
Enbridge Inc.	April 2024	senior notes	US$3,500
Enbridge Inc.	June 2024	fixed-to-fixed subordinated notes	US$1,200
Enbridge Inc.	August 2024	medium-term notes	$1,800
Algonquin Gas Transmission, LLC	July 2024	senior notes	US$350
East Tennessee Natural Gas, LLC	December 2024	senior notes	US$460
Questar Gas Company	December 2024	senior notes	US$200

Credit Facilities, Ratings and Liquidity

To ensure ongoing liquidity and to mitigate the risk of capital market disruption, we maintain ready 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, inclusive of term loans, at December 31, 2024:

(millions of Canadian dollars)	Maturity[1]	Total Facilities	Draws[2]	Available
Enbridge Inc.	2025-2049	**8,840**	**5,843**	**2,997**
Enbridge (U.S.) Inc.	2026-2029	**10,813**	**4,707**	**6,106**
Enbridge Pipelines Inc.	2026	**2,000**	**509**	**1,491**
Enbridge Gas Inc.	2026	**2,500**	**530**	**1,970**
Total committed credit facilities		**24,153**	**11,589**	**12,564**

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 March 2024, we entered into a delayed-draw term loan facility in support of sustainable retrofit projects for large buildings using decarbonization solutions for $200 million which matures in March 2049.

In June 2024, we entered into a five-year, non-revolving term loan facility of US$250 million which matures in June 2029.

In July 2024, we renewed approximately $8.8 billion of our 364-day extendible credit facilities, extending the maturity dates to July 2026, which includes a one-year term out provision from July 2025. We also renewed approximately $7.8 billion of our five-year credit facilities, extending the maturity dates to July 2029. Further, we extended the maturity dates of our three-year credit facilities to July 2027.

In July 2024, Enbridge Gas Ontario extended the maturity date of its 364-day extendible credit facility to July 2026, which includes a one-year term out provision from July 2025.

In July 2024, Enbridge Pipelines Inc. extended the maturity date of its 364-day extendible credit facility to July 2026, which includes a one-year term out provision from July 2025.

In January 2024 and October 2024, we entered into new letters of credit facilities and increased our letter of credit facilities by $146 million and $200 million, respectively.

In addition to the committed credit facilities noted above, we maintain $1.4 billion of uncommitted demand letter of credit facilities, of which $931 million was unutilized as at December 31, 2024. As at December 31, 2023, we had $1.1 billion of uncommitted demand letter of credit facilities, of which $572 million was unutilized.

As at December 31, 2024, our net available liquidity totaled $14.4 billion (2023 - $23.0 billion), consisting of available credit facilities of $12.6 billion (2023 - $17.1 billion) and unrestricted Cash and cash equivalents of $1.8 billion (2023 - $5.9 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, 2024, we were in compliance with all debt covenants and expect to continue to comply with such covenants.

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.

Credit Ratings Action
On March 29, 2024, Moody's Investor Service (Moody's) downgraded Enbridge's credit ratings for our senior unsecured debt ratings to Baa2 from Baa1. Moody's also downgraded the credit ratings of our subsidiaries: Enbridge Energy Partners, L.P. (EEP), Enbridge Energy Limited Partnership, Spectra Energy Partners, LP (SEP) and Texas Eastern. The outlooks of all five entities were changed to stable from negative.

In June 2024, Standard & Poor's Global revised Enbridge's and EEP's outlooks from negative to stable.

On June 28, 2024, Morningstar DBRS (DBRS) upgraded Enbridge's credit ratings for our senior unsecured debt ratings to A (low) from BBB (high). DBRS also updated the credit rating of EEP to A (low) with a stable trend.

There are no material restrictions on our cash. Total Restricted cash of $92 million, as reported in the Consolidated Statements of Financial Position, primarily includes cash collateral and future pipeline abandonment costs collected and held in trust. Cash and cash equivalents held by certain subsidiaries may not be readily accessible for alternative use by us.

Excluding current maturities of long-term debt, as at December 31, 2024 and 2023, we had negative and positive working capital positions of $2.9 billion and $3.0 billion, respectively. In 2024, the major contributing factor to the negative working capital position was the current liabilities associated with our growth capital program compared to a positive working capital position in 2023, due to the increase in cash associated with pre-funding of the Acquisitions.

SOURCES AND USES OF CASH

Year ended December 31,	**2024**	2023	2022
(millions of Canadian dollars)			
Operating activities	**12,600**	14,201	11,230
Investing activities	**(20,363)**	(6,043)	(5,270)
Financing activities	**3,544**	(2,864)	(5,428)
Effect of translation of foreign denominated cash and cash equivalents and restricted cash	**234**	(216)	55
Net change in cash and cash equivalents and restricted cash	**(3,985)**	5,078	587

Significant sources and uses of cash for the years ended December 31, 2024 and 2023 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 under *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 and dispositions as discussed under *Recent Developments,* 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, 2024, 2023 and 2022 is set out below:

Year ended December 31,	**2024**	2023	2022
(millions of Canadian dollars)			
Liquids Pipelines	**1,157**	1,158	1,418
Gas Transmission	**2,453**	1,890	1,647
Gas Distribution and Storage	**2,381**	1,451	1,499
Renewable Power Generation	**661**	100	50
Eliminations and Other	**59**	55	33
Total capital expenditures	**6,711**	4,654	4,647

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 Delaware Basin Residue, LLC and contributions to our Fox Squirrel Solar investment in 2024.

The factors above were partially offset by proceeds received from the dispositions of our interests in the Alliance Pipeline, Aux Sable, and NRGreen in 2024.

2023
The increase in cash used in investing activities primarily resulted from the following factors:

- the absence in 2023 of the proceeds received from the completion of a joint venture merger transaction for DCP Midstream, LLC in August 2022; and
- higher cash outflows related to acquisitions in 2023 when compared to 2022.

The factors above were partially offset by higher distributions in 2023 mainly related to our investment in NEXUS Gas Transmission, LLC.

Financing Activities
Cash provided by 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, share redemptions and common share repurchases under our NCIB. Cash provided by financing activities is also impacted by changes in distributions to, and contributions from, noncontrolling interests.

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

- net commercial paper and credit facility draws in 2024 when compared to net repayments during the same period in 2023;
- the ATM program, resulting 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 when compared to the same period in 2023.

The factors above were partially offset by:

- higher long-term debt repayments and lower long-term debt issuances in 2024 when compared to the same period in 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.

2023
The decrease in cash provided by financing activities primarily resulted from the following factors:

- higher long-term debt issuances in 2023 when compared to the same period in 2022;
- our public offering of common shares, which closed on September 8, 2023, resulting in the issuance of 102,913,500 common shares at a price of $44.70 per share for gross proceeds of $4.6 billion, which is intended to finance a portion of the aggregate cash consideration payable for the Acquisitions; and
- the absence in 2023 of the redemption of Preference Shares, Series 17 and Series J in the first and second quarters of 2022, respectively.

The factors above were partially offset by:

- higher net commercial paper and credit facility repayments in 2023 when compared to the same period in 2022;
- net repayments of short-term borrowings in 2023 when compared to net issuances in 2022;
- the absence in 2023 of proceeds received from the sale of a non-operating interest in seven pipelines from our Regional Oil Sands System in October 2022;
- higher long-term debt repayments in 2023 when compared to the same period in 2022; 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]	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%	$1.30052	$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%	$1.38452	$25	June 1, 2028	Series G
Preference Shares, Series G[5]	6.15%	$1.51644	$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]	5.76%	$1.42028	$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[7]	5.92%	$1.47952	$25	March 1, 2029	Series Q
Preference Shares, Series R[8]	6.31%	$1.57852	$25	June 1, 2029	Series S
Preference Shares, Series 1	6.70%	US$1.67592	US$25	June 1, 2028	Series 2
Preference Shares, Series 3[9]	5.29%	$1.32200	$25	September 1, 2029	Series 4
Preference Shares, Series 4[10]	6.02%	$1.48440	$25	September 1, 2029	Series 3
Preference Shares, Series 5[11]	6.68%	US$1.67076	US$25	March 1, 2029	Series 6
Preference Shares, Series 7[12]	5.99%	$1.49700	$25	March 1, 2029	Series 8
Preference Shares, Series 9[13]	5.67%	$1.41800	$25	December 1, 2029	Series 10
Preference Shares, Series 11	3.94%	$0.98452	$25	March 1, 2025	Series 12
Preference Shares, Series 13	3.04%	$0.76076	$25	June 1, 2025	Series 14
Preference Shares, Series 15	2.98%	$0.74576	$25	September 1, 2025	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. These Dividend Rates are presented in the table above on an annualized basis using the most recent quarterly dividend rate reset. 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 $0.37911 from $0.43014 on December 1, 2024 due to reset on a quarterly basis.*

6 *The quarterly dividend per share paid on Preference Shares, Series I was decreased to $0.35507 from $0.40589 on December 1, 2024 due to reset on a quarterly basis.*

7 *The quarterly dividend per share paid on Preference Shares, Series P was increased to $0.36988 from $0.27369 on March 1, 2024 due to reset of the annual dividend on March 1, 2024.*

8 *The quarterly dividend per share paid on Preference Shares, Series R was increased to $0.39463 from $0.25456 on June 1, 2024 due to reset of the annual dividend on June 1, 2024.*

9 *The quarterly dividend per share paid on Preference Shares, Series 3 was increased to $0.33050 from $0.23356 on September 1, 2024 due to reset of the annual dividend on September 1, 2024.*

10 *On September 1, 2024, 1,502,775 of the outstanding Preference Shares, Series 3 were converted into Preference Shares, Series 4. The quarterly dividend per share paid on Preference Shares, Series 4 was decreased to $0.37110 from $0.42206 on December 1, 2024 due to reset on a quarterly basis following the date of issuance.*

11 *The quarterly dividend per share paid on Preference Shares, Series 5 was increased to US$0.41769 from US$0.33596 on March 1, 2024 due to reset of the annual dividend on March 1, 2024.*

12 *The quarterly dividend per share paid on Preference Shares, Series 7 was increased to $0.37425 from $0.27806 on March 1, 2024 due to reset of the annual dividend on March 1, 2024.*

13 *The quarterly dividend per share paid on Preference Shares, Series 9 was increased to $0.35450 from $0.25606 on December 1, 2024 due to reset of the annual dividend on December 1, 2024.*

DIVIDENDS

We have paid common share dividends in every year since we became a publicly traded company in 1953. In December 2024, we announced a 3.0% increase in our quarterly dividend to $0.9425 per common share, or $3.77 annualized, effective with the dividend payable on March 1, 2025, thereby declaring a dividend increase for 30 straight years.

For the years ended December 31, 2024 and 2023, total dividends paid in cash were $7.9 billion and $7.3 billion, respectively, and reflected in Cash Flows from Financing Activities in the Consolidated Statements of Cash Flows.

On December 2, 2024, our Board of Directors declared the following quarterly dividends. All dividends are payable on March 1, 2025 to shareholders of record on February 14, 2025.

	Dividend per share
Common Shares[1]	$0.94250
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]	$0.37911
Preference Shares, Series H	$0.38200
Preference Shares, Series I[3]	$0.35507
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]	$0.37110
Preference Shares, Series 5	US$0.41769
Preference Shares, Series 7	$0.37425
Preference Shares, Series 9[5]	$0.35450
Preference Shares, Series 11	$0.24613
Preference Shares, Series 13	$0.19019
Preference Shares, Series 15	$0.18644
Preference Shares, Series 19	$0.38825

1 *The quarterly dividend per common share was increased 3.0% to $0.9425 from $0.9150, effective March 1, 2025.*

2 *The quarterly dividend per share paid on Preference Shares, Series G was decreased to $0.37911 from $0.43014 on December 1, 2024 due to reset on a quarterly basis.*

3 *The quarterly dividend per share paid on Preference Shares, Series I was decreased to $0.35507 from $0.40589 on December 1, 2024 due to reset on a quarterly basis.*

4 *The quarterly dividend per share paid on Preference Shares, Series 4 was decreased to $0.37110 from $0.42206 on December 1, 2024 due to reset on a quarterly basis following the date of issuance.*

5 *The quarterly dividend per share paid on Preference Shares, Series 9 was increased to $0.35450 from $0.25606 on December 1, 2024 due to reset of the annual dividend on December 1, 2024.*

SUMMARIZED FINANCIAL INFORMATION

On January 22, 2019, Enbridge entered into supplemental indentures with its wholly-owned subsidiaries, SEP and EEP (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 Guarantee

SEP Notes[1]	EEP Notes[2]
3.50% Senior Notes due 2025	5.88% Notes due 2025
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, 2024, the aggregate outstanding principal amount of SEP notes was approximately US$2.2 billion.
2 As at December 31, 2024, the aggregate outstanding principal amount of EEP notes was approximately US$2.4 billion.

Enbridge Notes under Guarantees

USD Denominated[1]	CAD Denominated[2]
2.50% Senior Notes due 2025	2.44% Senior Notes due 2025
2.50% Senior Notes due 2025	3.20% Senior Notes due 2027
4.25% Senior Notes due 2026	5.70% Senior Notes due 2027
1.60% Senior Notes due 2026	6.10% Senior Notes due 2028
5.90% Senior Notes due 2026	4.90% Senior Notes due 2028
3.70% Senior Notes due 2027	2.99% Senior Notes due 2029
5.25% Senior Notes due 2027	7.22% Senior Notes due 2030
6.00% Senior Notes due 2028	4.21% Senior Notes due 2030
3.13% Senior Notes due 2029	7.20% Senior Notes due 2032
5.30% Senior Notes due 2029	6.10% Sustainability-Linked Senior Notes due 2032
6.20% Senior Notes due 2030	3.10% Sustainability-Linked Senior Notes due 2033
2.50% Sustainability-Linked Senior Notes due 2033	5.36% Sustainability-Linked Senior Notes due 2033
5.70% Sustainability-Linked Senior Notes due 2033	4.73% Senior Notes due 2034
5.63% Senior Notes due 2034	5.57% Senior Notes due 2035
4.50% Senior Notes due 2044	5.75% Senior Notes due 2039
5.50% Senior Notes due 2046	5.12% Senior Notes due 2040
4.00% Senior Notes due 2049	4.24% Senior Notes due 2042
3.40% Senior Notes due 2051	4.57% Senior Notes due 2044
6.70% Senior Notes due 2053	4.87% Senior Notes due 2044
5.95% Senior Notes due 2054	4.10% Senior Notes due 2051
	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, 2024, the aggregate outstanding principal amount of the Enbridge US dollar denominated notes was approximately US$17.0 billion.

2 As at December 31, 2024, the aggregate outstanding principal amount of the Enbridge Canadian dollar denominated notes was approximately $12.3 billion.

Rule 3-10 of the US Securities and Exchange Commission's (SEC) Regulation S-X provides an exemption from the reporting requirements of the *Securities Exchange Act of 1934*, as amended (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 the Summarized Combined Statements of Financial Position combines the balances of EEP, SEP and Enbridge.

Summarized Combined Statement of Earnings

Year ended December 31,	2024
(millions of Canadian dollars)	
Operating loss	**(99)**
Loss	**(389)**
Loss attributable to common shareholders	**(777)**

Summarized Combined Statements of Financial Position

December 31,	**2024**	2023
(millions of Canadian dollars)		
Cash and cash equivalents	**2,000**	6,525
Accounts receivable from affiliates	**3,901**	3,440
Short-term loans receivable from affiliates	**3,892**	3,291
Other current assets	**499**	491
Long-term loans receivable from affiliates	**54,416**	45,702
Other long-term assets	**2,139**	3,303
Accounts payable to affiliates	**2,252**	2,264
Short-term loans payable to affiliates	**1,188**	807
Trade payable and accrued liabilities	**661**	743
Other current liabilities	**8,047**	7,256
Long-term loans payable to affiliates	**36,576**	35,556
Other long-term liabilities	**62,642**	52,096

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 our continued use of Line 5 to transport crude oil and related liquids across the Reservation is a public nuisance under federal and state law and that the pipeline is in trespass on certain tracts of land in which the Band possesses 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 an answer, defenses and counterclaims.

On August 29, 2022, the Government of Canada released a statement formally invoking the dispute settlement provisions of the 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 to an injunction, with the level of damages and scope of the injunction to be determined at trial, which occurred October 24 through November 1, 2022.

On May 9, 2023, the Band filed an Emergency Motion for Injunctive Relief asking the Court to require Enbridge to purge and shutdown Line 5 on the Reservation due to significant erosion at the Meander. Enbridge responded and a hearing was held on May 18, 2023 in front of Judge Conley who indicated that he did not find the Band had proven imminence but that his final ruling on all issues would be provided soon.

On June 26, 2023, the Court issued its Final Order ruling as follows: (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 pay money on a quarterly basis using the formula set in its Order as long as Line 5 operates in trespass on the 12 allotted parcels (approximately $400,000 per year); (4) Enbridge must cease operation of Line 5 on any parcel within the Band's tribal territory without 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 the Relocation to be completed 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 7th Circuit requested the US to file a brief in this appeal as amicus curiae to address the effect of the Agreement Between the US and Canada Concerning Transit Pipelines, 28 U.S.T. 7449 (1977), and any other issues that the US believes to be material. Subsequently, the US filed its brief on April 8, 2024. As invited by the Court of Appeals, Enbridge and the Band filed their respective responses to the US amicus brief on April 29, 2024. We anticipate the Court of Appeals will issue a decision in early 2025.

MICHIGAN LINE 5 DUAL PIPELINES - STRAITS OF MACKINAC EASEMENT

Michigan Attorney General Lawsuit

In 2019, the Michigan Attorney General (AG) filed a complaint in the Michigan Ingham County Circuit Court (the Circuit Court) that requests the Circuit Court to declare the easement granted to Enbridge in 1953 for the operation of Line 5 in the Straits of Mackinac (the Straits) to be invalid and to prohibit continued operation of Line 5 in the Straits. On December 15, 2021, Enbridge removed the case to the US District Court in the Western District of Michigan (US District Court). The removal of the AG's case to federal court followed a November 16, 2021 ruling which held that the similar (and now dismissed) 2020 lawsuit brought by the Governor of Michigan to force Line 5's shutdown raised important federal issues that should be heard in federal court. The AG subsequently filed various motions and appeals (opposed by Enbridge) to remand the case.

On June 17, 2024, the 6th Circuit Court of Appeals (6th Circuit) overturned the US District Court’s decision and remanded the AG's lawsuit against Enbridge back to the Circuit Court. On July 15, 2024, Enbridge filed a petition for rehearing, which was denied on August 16, 2024.

Briefing by both parties was concluded on December 23, 2024.

Oral argument took place before the Circuit Court judge on January 27, 2025, on cross motions for summary disposition which have been pending for almost four years. We anticipate a decision on the motions for summary disposition in 2025.

On January 13, 2025, Enbridge filed a petition for certiorari with the US Supreme Court. The petition asks the Supreme Court to review and reverse the June 2024 decision of the 6th Circuit remanding to state court the Michigan Attorney General’s lawsuit against Enbridge seeking to shut down Line 5.

Enbridge Lawsuit

On November 24, 2020, Enbridge filed in the US District Court a Complaint for Declaratory and Injunctive Relief requesting that the US District Court enjoin the State of Michigan Officials from taking any action to prevent or impede the operation of Line 5. The Government of Canada has filed a supplemental brief reiterating that the 1977 Transit Pipelines Treaty between the US and Canada has been invoked and that the matter is of great importance to Canada. This matter remains in federal court.

In January 2022, the State of Michigan Officials filed a motion to dismiss Enbridge's Complaint and Enbridge filed a motion for summary judgment. On July 5, 2024, the US District Court issued an Order denying the Michigan officials' motion to dismiss Enbridge's Complaint, and the State of Michigan Officials filed for an immediate appeal to the 6th Circuit. On August 29, 2024, the US District Court issued an order staying the case, pending the 6th Circuit's decision.

Briefing on the appeal concluded on December 20, 2024; oral argument is scheduled for March 18, 2025, with an expected decision in 2025.

DAKOTA ACCESS PIPELINE

We own an effective interest of 27.6% in the Bakken Pipeline System, which is inclusive of 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) contesting the lawfulness of the Army Corps easement for DAPL, including 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.

On June 14, 2017, the District Court found the Army Corps' environmental review to be deficient and ordered the Army Corps to conduct further study concerning spill risks from DAPL.

On March 25, 2020, in response to amended complaints from the Tribes, the District Court found that the Army Corps' subsequent environmental review completed in August 2018 was also deficient and ordered the Army Corps to prepare an Environmental Impact Statement (EIS) to address unresolved controversy pertaining to potential spill impacts resulting from DAPL. On July 6, 2020, the District Court issued an order vacating the Army Corps' easement for DAPL and ordering that the pipeline be shut down by August 5, 2020. On that day, the US Court of Appeals for the District of Columbia Circuit stayed the District Court's July 6 order to shut down and empty the pipeline.

On January 26, 2021, the US Court of Appeals affirmed the District Court's decision, holding that the Army Corps is required to prepare an EIS and that the Army Corps' easement for DAPL is vacated. The US Supreme Court subsequently denied the request of Dakota Access, LLC to review the decision that an EIS is required. The US Court of Appeals also determined that, absent an injunction proceeding, the District Court could not order DAPL's operations to cease. While not an issue before, the US Court of Appeals also recognized that the Army Corps could consider whether to allow DAPL to continue to operate in the absence of an easement. The Army Corps earlier indicated that it did not intend to exercise its authority to bar DAPL's continued operation, notwithstanding the absence of an easement.

On September 8, 2023, the Army Corps issued its draft EIS, which assesses the impacts of DAPL under five alternative scenarios: denying the easement removing the pipeline; denying the easement and leaving the pipeline in place; granting the easement with the prior conditions (which allow for the ongoing operation, maintenance and ultimate removal of the pipeline and its related facilities); granting the easement with some new safety conditions; and rerouting the pipeline. The Army Corps did not identify a preferred alternative. The public comment period that commenced on the issuance of the draft EIS closed on December 13, 2023. The pipeline will remain operational while the environmental review process continues. The final EIS is expected to be issued in 2025.

On October 15, 2024, the Standing Rock Sioux Tribe filed a complaint in the DC District Court against the Army Corps, among others, seeking a permanent injunction prohibiting the continued operation of DAPL. The main allegations of the complaint are that the Army Corps is unlawfully permitting DAPL to continue to operate without an easement and without a determination under the *National Environmental Policy Act,* and that the Army Corps has failed to require that a compliant Facility Response Plan be submitted. Several of the claims are similar to those in the litigation described above. Dakota Access, LLC and 13 states have intervened in the case in support of the Army Corps and continued operation of DAPL. Dakota Access, LLC filed an answer to the complaint on December 19, 2024. On January 17, 2025, the Federal Defendants, Dakota Access LLC, and the 13 States filed motions to dismiss the Standing Rock Sioux Tribe's complaint. Also on January 17, 2025, the Standing Rock Sioux Tribe filed a motion for partial summary judgment on its claims. We expect that these recent motions will require additional briefing in 2025.

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.

TAX MATTERS

We and our subsidiaries maintain tax liabilities related to uncertain tax positions. While fully supportable in our view, these tax positions, if challenged by tax authorities, may not be fully sustained on review.

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.

BUSINESS COMBINATIONS

We apply the provisions of Accounting Standards Codification 805 *Business Combinations* in accounting for our business acquisitions. The acquired assets and assumed liabilities are recorded at their estimated fair values as at the date of acquisition. Goodwill represents the excess of the purchase price over the fair value of net identifiable assets. While we use our best estimates and assumptions to accurately value assets acquired and liabilities assumed at the date of acquisition, as well as any contingent consideration, our estimates are inherently uncertain and subject to refinement. During the measurement period, which may be up to one year from the acquisition date, we record adjustments to the assets acquired and liabilities assumed with a corresponding offset to goodwill. Upon conclusion of the measurement period, or the final determination of values for assets acquired or liabilities assumed, whichever comes first, any subsequent adjustments are recorded in the Consolidated Statements of Earnings.

Accounting for business combinations requires significant judgment, estimates and assumptions at the acquisition date. In developing estimates of fair values at the acquisition date, we utilize a variety of factors including market data, historical and future expected cash flows, growth rates and discount rates. The subjective nature of our assumptions increases the risk associated with estimates surrounding the projected performance of the acquired entity.

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 a discounted cash flow technique. 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 and working capital levels, 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 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, 2024, we performed our annual goodwill impairment assessment which consisted of a qualitative assessment for the Liquids Pipelines, Gas Transmission, Gas Distribution and Storage, and Renewable Power Generation reporting units and did not identify impairment indicators. No indicators of goodwill impairment were identified during the remainder of 2024.

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.

ASSETS HELD FOR SALE

We classify assets as held for sale when management commits to a formal plan to actively market an asset or a group of assets and when management believes it is probable the sale of the assets will occur within one year. We measure assets classified as held for sale at the lower of their carrying value and their estimated fair value less costs to sell.

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.

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

As at December 31, 2024 and 2023, our regulatory assets totaled $7.6 billion and $5.7 billion, respectively, and regulatory liabilities totaled $6.7 billion and $3.8 billion, respectively.

DEPRECIATION

Depreciation of property, plant and equipment, our largest asset with a net book value at December 31, 2024 and 2023, of $131.1 billion and $104.6 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, 2024 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	296	16	94	7
Decrease in expected return on assets	—	22	—	9
Decrease in rate of salary increase	(59)	(10)	(20)	(2)
OPEB				
Decrease in discount rate	14	1	8	—
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 year ended December 31, 2024 and 2023 ranged from 1.5% to 9.0%. ARO is added to the carrying value of the associated asset and depreciated over the asset's useful life. The corresponding liability is accreted over time through charges to earnings and is reduced by actual costs of decommissioning and reclamation. Our estimates of retirement costs could change as a result of changes in cost estimates and regulatory requirements. Currently, for the majority of our assets, 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*.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Our earnings, cash flows and other comprehensive income (OCI) are subject to movements in foreign exchange rates, interest rates, commodity prices and our share price.

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

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

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

Interest Rate Risk
Our earnings, cash flows and OCI are exposed to short-term interest rate variability due to the regular repricing of our variable rate debt, primarily commercial paper. We have a policy of limiting the maximum floating rate debt to 30% of total debt outstanding. To ensure compliance with our policy, we monitor and adjust our debt portfolio mix of fixed and variable rate debt instruments in conjunction with the use of hedging instruments. We have implemented a hedging program to partially mitigate the impact of short-term interest rate volatility on interest expense via the execution of floating-to-fixed interest rate swaps and costless collars. These swaps have an average fixed rate of 3.6%.

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

Commodity Price Risk

Our earnings, cash flows and OCI are exposed to changes in commodity prices as a result of our ownership interests in certain assets and investments, as well as through the activities of our energy marketing subsidiaries. These commodities include natural gas, crude oil, power and NGL. We employ financial and physical derivative instruments to fix a portion of the variable price exposures that arise from physical transactions involving these commodities. We use primarily non-qualifying derivative instruments to manage commodity price risk.

Equity Price Risk

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

Market Risk Management

We have a Risk Policy to minimize the likelihood that adverse cash flow impacts arising from movements in market prices will exceed a defined risk tolerance. We identify and measure all material market risks including commodity price risks, interest rate risks, foreign exchange risk and equity price risk using a standardized measurement methodology. Our market risk metric consolidates the exposure after accounting for the impact of offsetting risks and limits the consolidated cash flow volatility arising from market related risks to an acceptable approved risk tolerance threshold. Our market risk metric is Cash Flow at Risk (CFaR).

CFaR is a statistically derived measurement used to measure the maximum cash flow loss that could potentially result from adverse market price movements over a one month holding period for price sensitive non-derivative exposures and for derivative instruments we hold or issue as recorded in the Consolidated Statements of Financial Position as at December 31, 2024. CFaR assumes that no further mitigating actions are taken to hedge or otherwise minimize exposures and the selection of a one month holding period reflects the mix of price risk sensitive assets at Enbridge. As a practical matter, a large portion of Enbridge’s exposure could be hedged or unwound in a much shorter period if required to mitigate the risks.

The consolidated CFaR policy limit for Enbridge is 3.5% of its forward 12 month normalized cash flow. At December 31, 2024 and 2023 CFaR was $113 million and $100 million or 0.9% and 0.9%, respectively, of estimated 12 month forward normalized cash flow.

LIQUIDITY RISK
Liquidity risk is the risk that we will not be able to meet our financial obligations, including commitments and guarantees, as they become due. In order to mitigate this risk, we forecast cash requirements over a 12 month rolling time period to determine whether sufficient funds will be available. Our primary sources of liquidity and capital resources are funds generated from operations, the issuance of commercial paper and draws under committed credit facilities and long-term debt, which includes debentures and medium-term notes. Our shelf prospectuses with securities regulators enable ready access to either the Canadian or US public capital markets, subject to market conditions. In addition, we maintain sufficient liquidity through committed credit facilities with a diversified group of banks and institutions which, if necessary, enables us to fund all anticipated requirements for approximately one year without accessing the capital markets. We were in compliance with all the terms and conditions of our committed credit facility agreements and term debt indentures as at December 31, 2024. As a result, all credit facilities are available to us and the banks are obligated to fund us under the terms of the facilities. We also identify other potential sources of debt and equity funding alternatives, including reinstatement of our dividend reinvestment and share purchase plan or at-the-market equity issuances.

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

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

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

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholders of Enbridge Inc.

Opinions on the Financial Statements and Internal Control over Financial Reporting

We have audited the accompanying consolidated statements of financial position of Enbridge Inc. and its subsidiaries (the Company) as of December 31, 2024 and 2023, and the related consolidated statements of earnings, of comprehensive income, of changes in equity and of cash flows for each of the three years in the period ended December 31, 2024, including the related notes (collectively referred to as the consolidated financial statements). We also have audited the Company's internal control over financial reporting as of December 31, 2024, based on criteria established in *Internal Control – Integrated Framework* (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2024 and 2023, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2024 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2024, based on criteria established in *Internal Control – Integrated Framework* (2013) issued by the COSO.

Basis for Opinions

The Company's management is responsible for these consolidated financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in Management's Annual Report on Internal Control over Financial Reporting appearing under Item 9A. Our responsibility is to express opinions on the Company's consolidated financial statements and on the Company's internal control over financial reporting based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

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

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

As described in Management's Annual Report on Internal Control over Financial Reporting, management has excluded The East Ohio Gas Company, Questar Gas Company and its related Wexpro entities, and Public Service Company of North Carolina, Incorporated from its assessment of internal control over financial reporting as of December 31, 2024 because they were acquired separately by the Company in business combinations during 2024. We have also excluded The East Ohio Gas Company, Questar Gas Company and its related Wexpro entities, and Public Service Company of North Carolina, Incorporated from our audit of internal control over financial reporting. The East Ohio Gas Company, Questar Gas Company and its related Wexpro entities, and Public Service Company of North Carolina, Incorporated are wholly-owned subsidiaries whose total assets and total revenues excluded from management's assessment and our audit of internal control over financial reporting collectively represent approximately 11% and 4%, respectively, of the related consolidated financial statement amounts as of and for the year ended December 31, 2024.

Definition and Limitations of Internal Control over Financial Reporting

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

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

Critical Audit Matters

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

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

As described in Notes 2 and 15 to the consolidated financial statements, the Company's goodwill balance was $36,600 million as at December 31, 2024 which includes goodwill balances of $18,278 million and $8,892 million related to the GT and GDS reporting units respectively. An annual goodwill impairment assessment is performed at the reporting unit level as of April 1 of each year, or more frequently if events or circumstances indicate that the carrying value of goodwill may be impaired. Management has the option to first assess qualitative factors to determine whether it is necessary to perform the quantitative goodwill impairment assessment. When performing a qualitative assessment, management determines the drivers of fair value for each reporting unit and evaluates whether those drivers have been positively or negatively affected by relevant events and circumstances since the last fair value assessment. Management's 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 management's assessment of qualitative factors, if it is determined that 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. Management performed a qualitative goodwill impairment assessment as of April 1, 2024 and did not identify impairment indicators for the GT and GDS reporting units.

The principal considerations for our determination that performing procedures relating to the qualitative goodwill impairment assessment for the GT and GDS reporting units is a critical audit matter are the significant judgments required by management in assessing the drivers of fair value in the qualitative goodwill impairment assessment for the GT and GDS reporting units to determine whether further quantitative impairment testing is required. This led to a high degree of auditor judgment, effort and subjectivity in performing procedures related to management's assessment of drivers of fair value in the qualitative goodwill impairment assessment for the GT and GDS reporting units with respect to changes to projected cash flows from operations and expected future capital expenditures as well as the impact of changes in discount rate for the GT reporting unit and changes to rate base multiple and forecasted rate base for the GDS reporting unit. In addition, the audit effort involved the use of professionals with specialized skills and knowledge.

Addressing the matter involved performing procedures and evaluating audit evidence in connection with forming our overall opinion on the consolidated financial statements. These procedures included testing the effectiveness of controls relating to management's qualitative goodwill impairment assessment. These procedures also included, among others, evaluating the reasonableness of management's qualitative goodwill impairment assessment for the GT and GDS reporting units by assessing the reasonableness of changes to (i) projected cash flows from operations and expected future capital expenditures for the GT reporting unit and (ii) the forecasted rate base for the GDS reporting unit by considering the current and past performance of the GT and GDS reporting units, external industry data, and evidence obtained in other areas of the audit. Professionals with specialized skill and knowledge were used to assist in evaluating the reasonableness of management's qualitative goodwill impairment assessment for the GT and GDS reporting units, by assessing the reasonableness of the impact of changes in (i) discount rate for the GT reporting unit and (ii) the rate base multiple for the GDS reporting unit.

/s/PricewaterhouseCoopers LLP

Chartered Professional Accountants

Calgary, Canada
February 14, 2025

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

ENBRIDGE INC.
CONSOLIDATED STATEMENTS OF EARNINGS

Year ended December 31,	**2024**	2023	2022
(millions of Canadian dollars, except per share amounts)			
Operating revenues			
Commodity sales	**27,018**	18,981	29,150
Gas distribution sales	**6,802**	5,442	6,237
Transportation and other services	**19,653**	19,226	17,922
Total operating revenues *(Note 4)*	**53,473**	43,649	53,309
Operating expenses			
Commodity costs	**26,556**	18,526	28,942
Gas distribution costs	**2,484**	2,840	3,647
Operating and administrative	**9,427**	8,600	8,219
Depreciation and amortization	**5,167**	4,613	4,317
Impairment of long-lived assets	**190**	419	541
Impairment of goodwill	**—**	—	2,465
Total operating expenses	**43,824**	34,998	48,131
Operating income	**9,649**	8,651	5,178
Income from equity investments *(Note 13)*	**2,304**	1,816	2,056
Gain on disposition of equity investments *(Note 13)*	**1,091**	—	—
Gain on joint venture merger transaction *(Note 13)*	**—**	—	1,076
Other income/(expense) *(Note 27)*	**(1,326)**	1,224	(589)
Interest expense *(Note 17)*	**(4,419)**	(3,812)	(3,179)
Earnings before income taxes	**7,299**	7,879	4,542
Income tax expense *(Note 24)*	**(1,668)**	(1,821)	(1,604)
Earnings	**5,631**	6,058	2,938
(Earnings)/loss attributable to noncontrolling interests	**(190)**	133	65
Earnings attributable to controlling interests	**5,441**	6,191	3,003
Preference share dividends	**(388)**	(352)	(414)
Earnings attributable to common shareholders	**5,053**	5,839	2,589
Earnings per common share attributable to common shareholders *(Note 6)*	**2.34**	2.84	1.28
Diluted earnings per common share attributable to common shareholders *(Note 6)*	**2.34**	2.84	1.28

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

ENBRIDGE INC.
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Year ended December 31,	**2024**	2023	2022
(millions of Canadian dollars)			
Earnings	**5,631**	6,058	2,938
Other comprehensive income/(loss), net of tax			
Change in unrealized gain on cash flow hedges	**73**	220	847
Change in unrealized gain/(loss) on net investment hedges	**(1,305)**	409	(971)
Other comprehensive income/(loss) from equity investees	**(10)**	6	(6)
Excluded components of fair value hedges	**9**	12	(35)
Reclassification to earnings of loss on cash flow hedges	**23**	14	143
Reclassification to earnings of pension and other postretirement benefits (OPEB) amounts	**(16)**	(18)	(10)
Reclassification to earnings of loss on equity investees	**—**	—	16
Actuarial gain/(loss) on pension and OPEB	**248**	(130)	312
Foreign currency translation adjustments	**5,895**	(1,728)	4,406
Other comprehensive income/(loss), net of tax	**4,917**	(1,215)	4,702
Comprehensive income	**10,548**	4,843	7,640
Comprehensive (income)/loss attributable to noncontrolling interests	**(295)**	131	(21)
Comprehensive income attributable to controlling interests	**10,253**	4,974	7,619
Preference share dividends	**(388)**	(352)	(414)
Comprehensive income attributable to common shareholders	**9,865**	4,622	7,205

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

ENBRIDGE INC.
CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

Year ended December 31,	**2024**	2023	2022
(millions of Canadian dollars, except per share amounts)			
Preference shares *(Note 20)*			
Balance at beginning of year	**6,818**	6,818	7,747
Redemption of preference shares	**—**	—	(929)
Balance at end of year	**6,818**	6,818	6,818
Common shares *(Note 20)*			
Balance at beginning of year	**69,180**	64,760	64,799
Shares issued, net of issue costs	**2,489**	4,485	—
Shares issued on exercise of stock options	**39**	3	53
Shares issued on vesting of restricted stock units (RSU), net of tax	**30**	12	—
Share repurchases at stated value	**—**	(80)	(88)
Other	**—**	—	(4)
Balance at end of year	**71,738**	69,180	64,760
Additional paid-in capital			
Balance at beginning of year	**268**	275	365
Stock-based compensation	**98**	71	36
Stock options exercised	**(39)**	(3)	(50)
Vested RSUs	**(52)**	(20)	—
Purchase of noncontrolling interests	**—**	(28)	(43)
Other	**—**	(27)	(33)
Balance at end of year	**275**	268	275
Deficit			
Balance at beginning of year	**(17,115)**	(15,486)	(10,989)
Earnings attributable to controlling interests	**5,441**	6,191	3,003
Preference share dividends	**(388)**	(352)	(414)
Common share dividends declared	**(7,984)**	(7,423)	(7,023)
Share repurchases in excess of stated value	**—**	(45)	(63)
Balance at end of year	**(20,046)**	(17,115)	(15,486)
Accumulated other comprehensive income/(loss) *(Note 22)*			
Balance at beginning of year	**2,303**	3,520	(1,096)
Other comprehensive income/(loss) attributable to common shareholders, net of tax	**4,812**	(1,217)	4,616
Balance at end of year	**7,115**	2,303	3,520
Total Enbridge Inc. shareholders' equity	**65,900**	61,454	59,887
Noncontrolling interests *(Note 19)*			
Balance at beginning of year	**3,029**	3,511	2,542
Earnings/(loss) attributable to noncontrolling interests	**190**	(133)	(65)
Other comprehensive income/(loss) attributable to noncontrolling interests, net of tax			
Change in unrealized gain/(loss) on cash flow hedges	**9**	35	(28)
Foreign currency translation adjustments	**96**	(33)	114
	105	2	86
Comprehensive income/(loss) attributable to noncontrolling interests	**295**	(131)	21
Distributions	**(333)**	(363)	(259)
Contributions	**4**	11	1,105
Purchase of noncontrolling interests	**(2)**	2	55
Other	**—**	(1)	47
Balance at end of year	**2,993**	3,029	3,511
Total equity	**68,893**	64,483	63,398
Dividends paid per common share	**3.66**	3.55	3.44

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

ENBRIDGE INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS

Year ended December 31,	**2024**	2023	2022
(millions of Canadian dollars)			
Operating activities			
Earnings	**5,631**	6,058	2,938
Adjustments to reconcile earnings to net cash provided by operating activities:			
Depreciation and amortization	**5,167**	4,613	4,317
Deferred income tax expense *(Note 24)*	**719**	1,420	957
Unrealized derivative fair value (gain)/loss, net *(Note 23)*	**2,082**	(1,180)	1,280
Income from equity investments *(Note 13)*	**(2,304)**	(1,816)	(2,056)
Distributions from equity investments	**2,121**	1,998	1,827
Impairment of long-lived assets	**190**	419	541
Impairment of goodwill *(Note 15)*	**—**	—	2,465
Gain on joint venture merger transaction *(Note 13)*	**—**	—	(1,076)
Gain on disposition of equity investment	**(1,091)**	—	—
Other	**218**	378	49
Changes in operating assets and liabilities *(Note 28)*	**(133)**	2,311	(12)
Net cash provided by operating activities	**12,600**	14,201	11,230
Investing activities			
Capital expenditures	**(6,711)**	(4,654)	(4,647)
Long-term, restricted and other investments	**(3,416)**	(1,276)	(1,041)
Distributions from equity investments in excess of cumulative earnings	**785**	1,151	763
Additions to intangible assets	**(219)**	(222)	(174)
Acquisitions	**(13,472)**	(954)	(828)
Proceeds from joint venture merger transaction *(Note 13)*	**—**	—	522
Proceeds from dispositions of equity investments	**2,724**	—	—
Net change in affiliate loans	**2**	(27)	135
Other	**(56)**	(61)	—
Net cash used in investing activities	**(20,363)**	(6,043)	(5,270)
Financing activities			
Net change in short-term borrowings	**129**	(1,596)	481
Net change in commercial paper and credit facility draws	**6,549**	(8,157)	(1,333)
Debenture and term note issues, net of issue costs	**9,546**	15,377	7,547
Debenture and term note repayments	**(6,633)**	(4,819)	(4,198)
Sale of noncontrolling interest in subsidiary *(Note 8)*	**—**	—	1,092
Contributions from noncontrolling interests	**4**	11	13
Distributions to noncontrolling interests	**(333)**	(363)	(259)
Common shares issued, net of issue costs	**2,485**	4,450	3
Common shares repurchased	**—**	(125)	(151)
Preference share dividends	**(387)**	(352)	(338)
Common share dividends	**(7,875)**	(7,276)	(6,968)
Redemption of preference shares	**—**	—	(1,003)
Net change in affiliate loan	**99**	71	—
Other	**(40)**	(85)	(314)
Net cash provided by/(used in) financing activities	**3,544**	(2,864)	(5,428)
Effect of translation of foreign denominated cash and cash equivalents and restricted cash	**234**	(216)	55
Net change in cash and cash equivalents and restricted cash	**(3,985)**	5,078	587
Cash and cash equivalents and restricted cash at beginning of year	**5,985**	907	320
Cash and cash equivalents and restricted cash at end of year[1]	**2,000**	5,985	907
Supplementary cash flow information			
Cash paid for income taxes	**861**	578	495
Cash paid for interest, net of amount capitalized	**4,134**	3,380	2,920
Property, plant and equipment and intangible assets non-cash accruals	**1,251**	813	937

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

1 As at December 31, 2024, long-term restricted cash of $105 million (2023 and 2022 - nil) was included in Restricted long-term investments and cash in the Consolidated Statements of Financial Position.

ENBRIDGE INC.
CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

December 31,	**2024**	2023
(millions of Canadian dollars; number of shares in millions)		
Assets		
Current assets		
Cash and cash equivalents	**1,803**	5,901
Restricted cash	**92**	84
Trade receivables and unbilled revenues	**6,920**	4,410
Other current assets *(Note 9)*	**2,770**	2,440
Accounts receivable from affiliates	**90**	85
Inventory *(Note 10)*	**1,488**	1,479
	13,163	14,399
Property, plant and equipment, net *(Note 11)*	**131,104**	104,641
Long-term investments *(Note 13)*	**20,691**	16,793
Restricted long-term investments and cash *(Note 23)*	**998**	717
Deferred amounts and other assets	**11,034**	8,041
Intangible assets, net *(Note 14)*	**4,587**	3,537
Goodwill *(Note 15)*	**36,600**	31,848
Deferred income taxes *(Note 24)*	**796**	341
Total assets	**218,973**	180,317
Liabilities and equity		
Current liabilities		
Short-term borrowings *(Note 17)*	**529**	400
Trade payables and accrued liabilities	**7,060**	4,308
Other current liabilities *(Note 16)*	**7,241**	5,659
Accounts payable to affiliates	**22**	26
Interest payable	**1,231**	958
Current portion of long-term debt *(Note 17)*	**7,729**	6,084
	23,812	17,435
Long-term debt *(Note 17)*	**93,414**	74,715
Other long-term liabilities	**13,258**	8,653
Deferred income taxes *(Note 24)*	**19,596**	15,031
	150,080	115,834
Commitments and contingencies *(Note 30)*		
Equity		
Share capital *(Note 20)*		
Preference shares	**6,818**	6,818
Common shares *(2,178 and 2,125 outstanding at December 31, 2024 and 2023, respectively)*	**71,738**	69,180
Additional paid-in capital	**275**	268
Deficit	**(20,046)**	(17,115)
Accumulated other comprehensive income *(Note 22)*	**7,115**	2,303
Total Enbridge Inc. shareholders' equity	**65,900**	61,454
Noncontrolling interests *(Note 19)*	**2,993**	3,029
	68,893	64,483
Total liabilities and equity	**218,973**	180,317

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

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

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS
INDEX

1. BUSINESS OVERVIEW

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

Effective January 1, 2024, to better align how the chief operating decision maker (CODM) reviews operating performance and resource allocation across operating segments, we transferred our Canadian and United States (US) crude oil marketing businesses from the Energy Services segment to the Liquids Pipelines segment. As a result, the Energy Services segment ceased to exist and the remainder of the business, comprising natural gas and power marketing, is now reported in Eliminations and Other. Beginning in the first quarter of 2024, prior period comparable results for segmented information have been recast to reflect the change in reportable segments. This segment reporting change does not have an impact on our consolidated results.

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

LIQUIDS PIPELINES
Liquids Pipelines consists of pipelines and terminals in Canada and the US that transport and export various grades of crude oil and other liquid hydrocarbons, including the Mainline System, Regional Oil Sands System, Gulf Coast and Mid-Continent, and Other. Effective January 1, 2024, our Canadian and US crude oil marketing businesses are included in this segment. These businesses provide energy marketing services to customers and undertake physical commodity marketing activity and logistical services to manage our volume commitments on various pipeline systems.

GAS TRANSMISSION
Gas Transmission consists of our investments in natural gas pipelines and gathering and processing facilities in Canada and the US, including US Gas Transmission, Canadian Gas Transmission, US Midstream, and Other. This segment also includes certain investments in renewable natural gas (RNG) facilities. On January 2, 2024, we acquired six Morrow Renewables operating landfill gas-to-RNG production facilities (Tomorrow RNG) located in Texas and Arkansas which are a component of Other within the Gas Transmission segment *(Note 8)*. We also sold our interests in the Alliance Pipeline and Aux Sable (including a 42.7% interest in Aux Sable Midstream LLC and Aux Sable Liquid Products L.P., and a 50.0% interest in Aux Sable Canada LP), previously reported in the Gas Transmission segment, to Pembina Pipeline Corporation on April 1, 2024 *(Note 13)*.

GAS DISTRIBUTION AND STORAGE
Gas Distribution and Storage consists of our rate-regulated natural gas utility operations in Canada and the US. Enbridge Gas Inc. (Enbridge Gas Ontario) serves residential, commercial and industrial customers across Ontario. In 2024, we acquired three US natural gas utilities, 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), which make up our US gas utilities *(Note 8)*. This business segment also includes natural gas distribution activities in Québec.

RENEWABLE POWER GENERATION

Renewable Power Generation consists primarily of investments in wind and solar assets, as well as equity interests in geothermal power and power transmission assets. In North America, assets are primarily located in the provinces of Alberta, Ontario and Québec, and in the states of Colorado, Texas, Indiana, Ohio and West Virginia. We also hold interests in offshore wind facilities in operation, under construction and in active development in the United Kingdom, France and Germany. This segment also includes Tri Global Energy, LLC (TGE) which was acquired on September 27, 2022 *(Note 8).*

ELIMINATIONS AND OTHER

In addition to the segments described above, Eliminations and Other includes operating and administrative costs that are not allocated to business segments, the impact of foreign exchange hedge settlements and the activities of our wholly-owned captive insurance subsidiaries. The principal activity of our captive insurance subsidiaries is providing insurance and reinsurance coverage for certain insurable property and casualty risk exposures of our operating subsidiaries and certain equity investments. Eliminations and Other also includes new business development activities and corporate investments. Effective January 1, 2024, our natural gas and power marketing businesses are also included in Eliminations and Other.

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

2. SIGNIFICANT ACCOUNTING POLICIES

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

BASIS OF PRESENTATION AND USE OF ESTIMATES

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

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

PRINCIPLES OF CONSOLIDATION

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

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

REGULATION

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

Regulatory assets represent amounts that are expected to be recovered from customers in future periods through rates. Regulatory liabilities represent amounts that are expected to be refunded to customers in future periods through rates, amounts collected from customers in advance of costs being incurred, or to be paid to cover future abandonment costs and for future removal and site restoration costs as approved by the regulator. If there are changes in our assessment of the probability of recovery for a regulatory asset, we reduce its carrying amount to the balance that we expect to recover from customers in future periods through rates. If a regulator later excludes from allowable costs all or a part of costs that were capitalized as a regulatory asset, we reduce the carrying amount of the asset by the excluded amounts.

The recognition of regulatory assets and liabilities is based on the actions, or expected future actions, of the regulator. To the extent that the regulator's actions differ from our expectations, the timing and amount of recovery or settlement of regulatory balances could differ significantly from those recorded. In the absence of rate regulation, we would generally not recognize regulatory assets or liabilities and the earnings impact would be recorded in the period the expenses are incurred or revenues are earned. A regulatory asset or liability is recognized in respect of deferred income taxes when it is expected the amounts will be recovered or settled through future regulator-approved rates. We believe that the recovery of our regulatory assets as at December 31, 2024 is probable over the periods described in *Note 7 - Regulatory Matters*.

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

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

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

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

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

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

REVENUE RECOGNITION

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

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

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

For the years ended December 31, 2024, 2023 and 2022, cash received net of revenue recognized for contracts under make-up rights and similar deferred revenue arrangements was $97 million, $210 million and $238 million, respectively.

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

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

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

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

No non-affiliated customer exceeded 10.0% of our third-party revenues for the years ended December 31, 2024, 2023 and 2022.

DERIVATIVE INSTRUMENTS AND HEDGING

Non-qualifying Derivatives

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

Derivatives in Qualifying Hedging Relationships

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

Cash Flow Hedges

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

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

Fair Value Hedges

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

Net Investment Hedges

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

Classification of Derivatives

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

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

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

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

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

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

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

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

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

NONCONTROLLING INTERESTS
Noncontrolling interests represent ownership interests attributable to third parties in certain consolidated subsidiaries. The portion of equity not owned by us in such entities is reflected as Noncontrolling interests within the equity section of the Consolidated Statements of Financial Position.

INCOME TAXES

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

FOREIGN CURRENCY TRANSACTIONS AND TRANSLATION

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

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

CASH AND CASH EQUIVALENTS

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

LOANS AND RECEIVABLES

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

CURRENT EXPECTED CREDIT LOSSES

For accounts receivable, a loss allowance matrix is utilized to measure lifetime expected credit losses. The matrix contemplates historical credit losses by age of receivables, adjusted for any forward-looking information and management expectations. Other loan receivables and applicable off-balance sheet commitments utilize a discounted cash flow methodology which calculates the current expected credit losses based on historical default probability rates associated with the credit rating of the counterparty and the related term of the loan or commitment, adjusted for forward-looking information and management expectations. Trade receivables and unbilled revenues are presented net of allowance for expected credit losses of $119 million and $100 million as at December 31, 2024 and 2023, respectively.

NATURAL GAS IMBALANCES

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

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

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

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

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

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

LEASES
We recognize an arrangement as a lease when a customer has the right to obtain substantially all of the economic benefits from the use of an asset, as well as the right to direct the use of the asset. We recognize right-of-use (ROU) assets and the related lease liabilities in the Consolidated Statements of Financial Position for operating lease arrangements with a term of 12 months or longer. We do not separate non-lease components from the associated lease components of our lessee contracts and account for both components as a single lease component. We combine lease and non-lease components within a contract for operating lessor leases when certain conditions are met. ROU assets are assessed for impairment using the same approach applied for other long-lived assets.

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

DEFERRED AMOUNTS AND OTHER ASSETS

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

INTANGIBLE ASSETS

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

GOODWILL

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

We perform our annual review for impairment at the reporting unit level, which is identified by assessing whether the components of our operating segments constitute businesses for which discrete information is available, whether segment management regularly reviews the operating results of those components, and whether the economic and regulatory characteristics are similar. Our reporting units are Liquids Pipelines, Gas Transmission, Gas Distribution and Storage, and Renewable Power Generation.

We have the option to first assess qualitative factors to determine whether it is necessary to perform the quantitative goodwill impairment assessment. When performing a qualitative assessment, we determine the drivers of fair value for each reporting unit and evaluate whether those drivers have been positively or negatively affected by relevant events and circumstances since the last fair value assessment. Our evaluation includes, but is not limited to, the assessment of macroeconomic trends (including the impact of changes in discount rates and rate base multiple), changes to regulatory environments, capital accessibility, operating income trends (including changes to projected cash flows from operations, expected future capital expenditures and forecasted rate base), and changes to industry conditions. Based on our assessment of qualitative factors, if we determine it is more likely than not that the fair value of the reporting unit is less than its carrying amount, a quantitative goodwill impairment assessment is performed.

The quantitative goodwill impairment assessment involves determining the fair value of our reporting units and comparing those values to the carrying value of each reporting unit. If the carrying value of a reporting unit, including allocated goodwill, exceeds its fair value, goodwill impairment is measured at the amount by which the reporting unit's carrying value exceeds its fair value. This amount should not exceed the carrying amount of goodwill. The fair value of our reporting units is estimated using a discounted cash flow technique. 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 and working capital levels, 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 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, 2024, we performed our annual goodwill impairment assessment which consisted of a qualitative assessment for the Liquids Pipelines, Gas Transmission, Gas Distribution and Storage, and Renewable Power Generation reporting units and did not identify impairment indicators. No indicators of goodwill impairment were identified during the remainder of 2024.

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

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

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

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

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

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

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

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

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

Net periodic benefit cost is recognized in earnings and includes:

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

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

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

STOCK-BASED COMPENSATION

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

Performance stock units (PSU) and certain RSUs are cash-settled awards for which the related liability is remeasured each reporting period. PSUs vest at the completion of a three-year term and RSUs vest one-third annually from the grant date. During the vesting term, compensation expense is recorded based on the number of units outstanding and the current market price of Enbridge's common shares with an offset to Other current liabilities or Other long-term liabilities. The value of the PSUs is also dependent on our performance relative to targets set out under the plan. We also award share-settled RSUs to certain non-executive senior management employees which vest at the completion of a three-year term. Beginning in 2023, share-settled RSUs were also granted to non-executive employees, which vest either one-third annually from the grant date, or following a 12-month period. During the vesting term, compensation expense is recorded based on the number of units granted and the market price of Enbridge's common shares on the day immediately preceding the grant date, with an offset to Additional paid-in capital. There is no associated liability recorded for share-settled awards.

COMMITMENTS, CONTINGENCIES AND ENVIRONMENTAL LIABILITIES

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

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

3. CHANGES IN ACCOUNTING POLICIES

CHANGES IN ACCOUNTING POLICIES
There were no changes in accounting policies during the year ended December 31, 2024.

ADOPTION OF NEW ACCOUNTING STANDARDS
Segment Reporting
Effective January 1, 2024, with interim disclosure requirements effective after January 1, 2025, we adopted Accounting Standards Update (ASU) 2023-07 on a retrospective basis beginning on January 1, 2022. The new standard was issued in November 2023 to improve reportable segment disclosure requirements primarily through enhanced disclosures about significant segment expenses and to require in interim period financial statements all disclosures about a reportable segment's profit or loss and assets that are currently required annually. The ASU requires entities to disclose the title and position of the individual or the name of the group or committee identified as the CODM. The adoption of this ASU did not have a material impact on our consolidated financial statements.

FUTURE ACCOUNTING POLICY CHANGES
Income Tax Disclosures
ASU 2023-09 was issued in December 2023 to improve income tax disclosures by requiring specified categories in the annual rate reconciliation that meet quantitative thresholds and further disaggregation on income taxes paid by jurisdiction. ASU 2023-09 is effective January 1, 2025 and should be applied prospectively, with retrospective application being permitted. We are currently assessing the impact of the new standard on the presentation of *Note 24 - Income Taxes* to our consolidated financial statements.

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

4. REVENUE

Change in Revenue Classification
To better align the classification of revenues resulting from our acquisitions of the US gas utilities *(Note 8)*, we have made adjustments to Gas distribution sales and Transportation and other services revenues. Revenues generated from customers who procure their own gas but use our distribution system for delivery to the end use location have been reclassified to Gas distribution sales revenue from Transportation and other services revenue on the Consolidated Statements of Earnings and reclassified to Gas distribution sales from Transportation revenue in the Revenue from Contracts with Customers tables below. Our prior period comparable results have been recast to reflect the change in revenue classification. This change does not have an impact on our Total operating revenues.

REVENUE FROM CONTRACTS WITH CUSTOMERS
Major Products and Services

Year ended December 31, 2024	Liquids Pipelines	Gas Transmission	Gas Distribution and Storage	Renewable Power Generation	Eliminations and Other	Consolidated
(millions of Canadian dollars)						
Transportation revenue	**11,958**	**5,279**	**284**	**—**	**—**	**17,521**
Storage and other revenue	**255**	**573**	**509**	**—**	**—**	**1,337**
Gas distribution sales	**—**	**—**	**6,734**	**—**	**—**	**6,734**
Electricity and transmission revenue	**—**	**—**	**—**	**189**	**—**	**189**
Commodity sales	**—**	**158**	**—**	**—**	**—**	**158**
Total revenue from contracts with customers	**12,213**	**6,010**	**7,527**	**189**	**—**	**25,939**
Commodity sales	**25,689**	**99**	**—**	**—**	**1,072**	**26,860**
Other revenue[1,2]	**281**	**70**	**4**	**319**	**—**	**674**
Intersegment revenue	**—**	**20**	**11**	**6**	**(37)**	**—**
Total revenue	**38,183**	**6,199**	**7,542**	**514**	**1,035**	**53,473**

Year ended December 31, 2023	Liquids Pipelines	Gas Transmission	Gas Distribution and Storage	Renewable Power Generation	Eliminations and Other	Consolidated
(millions of Canadian dollars)						
Transportation revenue[3]	11,875	5,302	212	—	—	17,389
Storage and other revenue	257	461	355	—	—	1,073
Gas distribution sales[3]	—	—	5,461	—	—	5,461
Electricity and transmission revenue	—	—	—	259	—	259
Commodity sales	—	17	—	—	—	17
Total revenue from contracts with customers	12,132	5,780	6,028	259	—	24,199
Commodity sales	17,494	—	—	—	1,470	18,964
Other revenue[1,2]	257	72	(58)	215	—	486
Intersegment revenue	(1)	2	6	3	(10)	—
Total revenue	29,882	5,854	5,976	477	1,460	43,649

Year ended December 31, 2022	Liquids Pipelines	Gas Transmission	Gas Distribution and Storage	Renewable Power Generation	Eliminations and Other	Consolidated
(millions of Canadian dollars)						
Transportation revenue[3]	11,283	5,012	198	—	—	16,493
Storage and other revenue	235	350	308	—	—	893
Gas gathering and processing revenue	—	22	—	—	—	22
Gas distribution sales[3]	—	—	6,227	—	—	6,227
Electricity and transmission revenue	—	—	—	281	—	281
Total revenue from contracts with customers	11,518	5,384	6,733	281	—	23,916
Commodity sales	25,740	—	—	—	3,410	29,150
Other revenue[1,2]	(81)	39	(20)	305	—	243
Intersegment revenue	(3)	3	16	(4)	(12)	—
Total revenue	37,174	5,426	6,729	582	3,398	53,309

1 *Includes realized and unrealized gains and losses from our hedging program which were a net gain of $23 million and losses of $97 million and $431 million for the years ended December 31, 2024, 2023 and 2022, respectively.*
2 *Includes revenues from lease contracts. Refer to* Note 26 - Leases.
3 *These balances reflect a transfer from Transportation revenue to Gas distribution sales of $602 million and $584 million for the years ended December 31, 2023 and 2022, respectively.*

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

Contract Balances

	Contract Receivables	Contract Assets	Contract Liabilities
(millions of Canadian dollars)			
Balance as at December 31, 2024	**3,764**	**330**	**2,828**
Balance as at December 31, 2023	2,802	400	2,591

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

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

Contract liabilities represent payments received for performance obligations which have not been fulfilled. Contract liabilities primarily relate to make-up rights and deferred revenue. Revenue recognized during the year ended December 31, 2024 included in contract liabilities at the beginning of the year is $372 million. Increases in contract liabilities from cash received, net of amounts recognized as revenue during the year ended December 31, 2024, were $532 million.

Performance Obligations

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

There was no material revenue recognized during the year ended December 31, 2024 from performance obligations satisfied in previous periods.

Payment Terms

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

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

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

	Total	1 year	2-5 years	Thereafter
(billions of Canadian dollars)				
Expected revenue	62.6	10.4	25.2	27.0

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

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

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

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

Recognition and Measurement of Revenue

Year ended December 31, 2024	Liquids Pipelines	Gas Transmission	Gas Distribution and Storage	Renewable Power Generation	Consolidated
(millions of Canadian dollars)					
Revenue from products transferred at a point in time	**—**	**158**	**137**	**—**	**295**
Revenue from products and services transferred over time[1]	**12,213**	**5,852**	**7,390**	**189**	**25,644**
Total revenue from contracts with customers	**12,213**	**6,010**	**7,527**	**189**	**25,939**

Year ended December 31, 2023	Liquids Pipelines	Gas Transmission	Gas Distribution and Storage	Renewable Power Generation	Consolidated
(millions of Canadian dollars)					
Revenue from products transferred at a point in time	—	17	138	—	155
Revenue from products and services transferred over time[1]	12,132	5,763	5,890	259	24,044
Total revenue from contracts with customers	12,132	5,780	6,028	259	24,199

Year ended December 31, 2022	Liquids Pipelines	Gas Transmission	Gas Distribution and Storage	Renewable Power Generation	Consolidated
(millions of Canadian dollars)					
Revenue from products transferred at a point in time	—	—	127	—	127
Revenue from products and services transferred over time[1]	11,518	5,384	6,606	281	23,789
Total revenue from contracts with customers	11,518	5,384	6,733	281	23,916

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

Performance Obligations Satisfied Over Time

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

Determination of Transaction Prices

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

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

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

5. SEGMENTED INFORMATION

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

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

Year ended December 31, 2022	Liquids Pipelines	Gas Transmission	Gas Distribution and Storage	Renewable Power Generation	Total Reportable Segments
(millions of Canadian dollars)					
Operating revenues[1]	37,174	5,426	6,729	582	49,911
Commodity and gas distribution costs	(25,495)	—	(3,693)	(16)	(29,204)
Operating and administrative	(4,318)	(2,254)	(1,289)	(255)	(8,116)
Impairment of long-lived assets	(258)	—	—	(235)	(493)
Impairment of goodwill	—	(2,465)	—	—	(2,465)
Income from equity investments	785	1,133	1	141	2,060
Gain on joint venture merger transaction *(Note 13)*	—	1,076	—	—	1,076
Other income	53	210	79	45	387
Earnings before interest, income taxes and depreciation and amortization	7,941	3,126	1,827	262	13,156
Eliminations and Other					(1,118)
Depreciation and amortization					(4,317)
Interest expense *(Note 17)*					(3,179)
Earnings before income taxes					4,542

1 *Refer to* Note 4 - Revenue *for a reconciliation of segment Operating revenues to the Consolidated Statements of Earnings.*
2 *The Liquids Pipelines segment includes the impact of a gain resulting from the derecognition of a net regulatory liability due to the discontinuance of regulatory accounting for our Southern Lights Pipeline* (Note 7).

Capital Expenditures[1]

Year ended December 31,	**2024**	2023	2022
(millions of Canadian dollars)			
Liquids Pipelines	**1,157**	1,158	1,418
Gas Transmission	**2,571**	1,944	1,690
Gas Distribution and Storage	**2,386**	1,451	1,499
Renewable Power Generation	**661**	100	50
Eliminations and Other	**59**	55	33
	6,834	4,708	4,690

1 Includes the equity component of the AFUDC.

Property, Plant and Equipment

Year ended December 31,	**2024**	2023	2022
(millions of Canadian dollars)			
Liquids Pipelines	**53,863**	51,855	53,573
Gas Transmission	**34,683**	31,016	29,666
Gas Distribution and Storage	**38,636**	18,766	17,857
Renewable Power Generation	**3,612**	2,706	3,082
Eliminations and Other	**310**	298	282
	131,104	104,641	104,460

The measurement basis for preparation of segmented information is consistent with our significant accounting policies *(Note 2)*.

GEOGRAPHIC INFORMATION

Revenues[1]

Year ended December 31,	**2024**	2023	2022
(millions of Canadian dollars)			
Canada	**22,001**	23,781	27,498
US	**31,472**	19,868	25,811
	53,473	43,649	53,309

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

Property, Plant and Equipment[1]

December 31,	**2024**	2023
(millions of Canadian dollars)		
Canada	**48,873**	48,570
US	**82,231**	56,071
	131,104	104,641

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

6. EARNINGS PER COMMON SHARE

BASIC
Earnings per common share is calculated by dividing earnings attributable to common shareholders by the weighted average number of common shares outstanding.

DILUTED
The treasury stock method is used to determine the dilutive impact of stock options and share-settled RSUs. This method assumes any proceeds from the exercise of stock options and vesting of share-settled RSUs would be used to purchase common shares at the average market price during the period.

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

December 31,	**2024**	2023	2022
(number of shares in millions)			
Weighted average shares outstanding	**2,155**	2,056	2,025
Effect of dilutive options and RSUs	**3**	2	4
Diluted weighted average shares outstanding	**2,158**	2,058	2,029

For the years ended December 31, 2024, 2023 and 2022, 14.6 million, 19.3 million and 10.4 million, respectively, of anti-dilutive stock options with a weighted average exercise price of $54.37, $54.42 and $56.49, respectively, were excluded from the diluted earnings per common share calculation.

7. REGULATORY MATTERS

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

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

LIQUIDS PIPELINES

Canadian Mainline

Canadian Mainline includes the Canadian portion of our Mainline system. The Mainline Tolling Settlement (MTS), governs the tolls paid for products shipped on its Mainline System, with the exception of Lines 8 and 9 which are tolled on a separate basis and was approved by the CER on March 4, 2024. The MTS has a seven-and-a-half year term through the end of 2028 and continues with the previous CTS framework with a Canadian Local Toll for all volumes shipped on the Canadian Mainline and an International Joint Tariff for all volumes shipped from western Canadian receipt points to delivery points on our Lakehead System. We have recognized a regulatory asset of $2.0 billion as at December 31, 2024 (2023 - $1.9 billion) to offset deferred income taxes, as a CER rate order governing flow-through income tax treatment permits future recovery. No other material regulatory assets or liabilities are recognized under the terms of the MTS.

Southern Lights Pipeline

In February 2024, we entered into fixed-toll agreements for a five-year term. As at December 31, 2023, since we did not expect to renew the agreements under a cost-of-service toll methodology, Southern Lights Pipeline was no longer subject to rate-regulated accounting. As a result, $151 million of net regulatory liabilities, $92 million of regulatory tax assets and $23 million of regulatory deferred tax liabilities were derecognized in 2023.

GAS TRANSMISSION

British Columbia Pipeline and Maritimes & Northeast Canada

British Columbia (BC) Pipeline and Maritimes & Northeast Canada (M&N Canada) are regulated by the CER. Rates are approved by the CER through negotiated toll settlement agreements based on cost-of-service. Both our BC Pipeline and M&N Canada systems currently operate under the terms of their respective 2022-2026 and 2024-2025 settlement agreements, which stipulate an allowable return on equity (ROE) and the continuation and establishment of certain deferral and variance accounts. M&N Canada reached a toll settlement with shippers for the effective period from January 1, 2024 to December 31, 2025. On November 28, 2023, M&N Canada filed the 2024-2025 toll settlement agreement with the CER, which was approved on February 14, 2024, as filed.

US Gas Transmission

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

GAS DISTRIBUTION AND STORAGE

Enbridge Gas Ontario

Enbridge Gas Ontario's distribution rates, commencing in 2024, were set by the OEB under a five-year Incentive Regulation (IR) framework. The framework included the establishment of 2024 base rates on a cost-of-service basis, while rates for 2025 through 2028 will be established using a price cap mechanism. The price cap mechanism will establish new rates each year through an annual base rate adjustment to expense an incremental $50 million of capitalized overheads as operating and maintenance costs; annual base rate escalation at inflation less a 0.28% productivity factor; annual updates for certain costs to be passed through to customers; and, where applicable, it will provide for the recovery of material unexpected events and discrete incremental capital investments beyond those that can be funded through base rates. The price cap mechanism includes the continuation and establishment of certain deferral and variance accounts, as well as an earnings sharing mechanism that requires Enbridge Gas Ontario to share equally with customers any earnings in excess of 100 basis points over the allowed ROE, and share 90% of earnings in excess of 300 basis points over the allowed ROE.

Enbridge Gas Ohio

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

In October 2023, Enbridge Gas Ohio filed for a non-fuel base rate increase of $212 million projected to be effective January 2025. This base rate increase aims to recover investments in distribution infrastructure for the benefit of Ohio customers. The proposed rates would provide an ROE of 10.40% compared to the currently authorized 10.38%. Additionally, Enbridge Gas Ohio also requested approval for an alternative rate plan for the continuation and modification of the Pipeline Infrastructure Replacement (PIR) and the Capital Expenditure Program (CEP). On December 18, 2024, Enbridge Gas Ohio filed a Notice of Intent to Modify Filed Positions. The Notice of Intent indicated a willingness to accept a reduced annual revenue requirement increase (from $212 million to $60 million) and, if the reduced position were adopted, to forgo filing a new base rate case until October 31, 2027. The hearing began on January 13, 2025, and remains underway.

The PIR program aims to replace 25% of the pipeline system. In April 2022, the Ohio Commission extended the PIR program through 2026.

The CEP allows Enbridge Gas Ohio to defer depreciation expense, property tax expense and carrying costs at the debt rate of 6.5% on capital investments not covered by its PIR program. In September 2024, the Ohio Commission approved adjustments to CEP cost recovery rates for 2023 costs.

Enbridge Gas Utah, Enbridge Gas Wyoming and Enbridge Gas Idaho

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

Enbridge Gas Utah, Enbridge Gas Wyoming and Enbridge Gas Idaho use several mechanisms to manage costs and promote efficiency. They recover gas costs through a balance-account mechanism that adjusts rates periodically to reflect changes in natural gas prices. The Infrastructure Replacement Program allows Enbridge Gas Utah, Enbridge Gas Wyoming, and Enbridge Gas Idaho to earn a return on capital expenditures for infrastructure replacement. The CET decouples non-gas revenues from customer usage, enabling the collection of allowed revenue per customer and encourages energy conservation. The Energy Efficiency Program promotes natural gas conservation through advertising, rebates, and home energy plans. These costs are recovered through periodic rate adjustments. The Utah Commission approved the construction of natural gas infrastructure to extend services to rural Utah, including 30 miles of intermediate high-pressure pipeline and up to 500 service lines. Recent approvals also include adjustments in the rural expansion rate tracker.

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

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

FINANCIAL STATEMENT EFFECTS

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

December 31,	2024	2023	Recovery/Refund Period Ends
(millions of Canadian dollars)			
Current regulatory assets			
Purchase gas variance	**74**	15	2025
Under-recovery of fuel costs	**4**	75	2025
Deferred projects costs[1]	**90**	—	2025
Other current regulatory assets	**304**	380	2025
Total current regulatory assets[2] *(Note 9)*	**472**	470	
Long-term regulatory assets			
Deferred income taxes[3]	**4,698**	4,456	Various
Deferred projects costs[1]	**1,045**	—	Various
Long-term debt[4]	**318**	348	2032-2046
Negative salvage[5]	**136**	180	Various
Demand-side management costs	**237**	54	Various
Pension plan receivable[6]	**266**	1	Various
Other long-term regulatory assets	**447**	198	Various
Total long-term regulatory assets[2]	**7,147**	5,237	
Total regulatory assets	**7,619**	5,707	
Current regulatory liabilities			
Purchase gas variance	**292**	31	2025
Regulatory liability related to US income taxes[7]	**44**	—	2025
Other current regulatory liabilities	**280**	276	2025
Total current regulatory liabilities[8] *(Note 16)*	**616**	307	
Long-term regulatory liabilities			
Future removal and site restoration reserves[9]	**2,964**	1,693	Various
Regulatory liability related to US income taxes[7]	**2,021**	854	Various
Pipeline future abandonment costs *(Note 23)*	**826**	745	Various
Pension plan payable[6]	**59**	143	Various
Other long-term regulatory liabilities	**242**	86	Various
Total long-term regulatory liabilities[8]	**6,112**	3,521	
Total regulatory liabilities	**6,728**	3,828	

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

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

3 Represents the regulatory offset to deferred income tax liabilities to the extent that it is expected to be included in future regulator-approved rates and recovered from customers. The recovery period depends on the timing of the reversal of temporary differences. In the absence of rate-regulated accounting, this regulatory balance and the related earnings impact would not be recorded. The balance as at December 31, 2024 is net of regulatory deferred tax write-offs.

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

5 The negative salvage balance represents the recovery in future rates of the actual cost of removal of previously retired or decommissioned plant assets, as approved by the FERC.

6 Represents the regulatory offset to our pension liability to the extent that it is expected to be included in regulator-approved future rates and recovered from customers. The settlement period for this balance is not determinable. In the absence of rate-regulated accounting, this regulatory balance and the related pension expense would be recorded in earnings and OCI.

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

8. ACQUISITIONS AND DISPOSITION

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

The purchase price allocations for the PSNC Acquisition, Questar Acquisition and EOG Acquisition (together, the Acquisitions) were prepared on a preliminary basis and are subject to change as additional information becomes available concerning the fair values of the ARO and regulatory balances and their tax bases. Any adjustments to the purchase price allocations will be made as soon as practicable, but no later than one year from the date of each acquisition.

The Acquisitions further diversify, and are complementary to, our existing gas distribution operations.

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

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

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

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

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

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

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

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

Aitken Creek Gas Storage

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

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

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

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

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

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

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

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

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

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

Tri Global Energy, LLC

On September 27, 2022, through a wholly-owned US subsidiary, we acquired all of the outstanding common units in TGE for cash consideration of $295 million (US$215 million) plus potential contingent payments of up to $72 million (US$53 million) dependent on the achievement of performance milestones by TGE (the TGE Acquisition). TGE is an onshore renewable project developer in the US with a development portfolio of wind and solar projects. The TGE Acquisition enhances Enbridge's renewable power platform and accelerates our North American growth strategy.

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

(millions of Canadian dollars)	September 27, 2022
Fair value of net assets acquired:	
Current assets	5
Property, plant and equipment	3
Long-term investments	8
Intangible assets (a)	117
Long-term assets	3
Current liabilities	61
Long-term debt	18
Long-term liabilities (b)	105
Goodwill (c)	392
Purchase price:	
Cash	295
Contingent consideration (d)	49
	344

a) Intangible assets consist of compensation expected to be earned by TGE on existing development contracts once certain project development milestones are met. Fair value was determined using a discounted cash flow method which is an income-based approach to valuation that estimates the present value of future projected benefits from the contracts. The intangible assets will be amortized on a straight-line basis over an expected useful life of three and a half years.

b) Long-term liabilities consist primarily of obligations payable to third parties which are contingent on milestones being met for certain projects. Fair value represents the present value of the future cash flow payments at the date of the TGE Acquisition.

c) Goodwill is primarily attributable to expected future returns from new opportunities to develop wind and solar projects, as well as enhanced scale and operational diversity of our renewable projects portfolio. The goodwill balance recognized has been assigned to our Renewable Power Generation segment and is tax deductible over 15 years.

d) We agreed to pay additional contingent consideration of up to $72 million (US$53 million) to TGE's former common unit holders if performance milestones were met on certain projects. The $49 million (US$36 million) of contingent consideration recognized in the purchase price represents the fair value of contingent consideration at the date of acquisition. The fair value was determined using an income-based approach.

Upon completion of the TGE Acquisition, we began consolidating TGE. For the period beginning September 27, 2022 through to December 31, 2022, operating revenues and earnings attributable to common shareholders generated by TGE were immaterial. The impact to our supplemental pro forma consolidated operating revenues and earnings attributable to common shareholders for the years ended December 31, 2022 and 2021, as if the TGE Acquisition had been completed on January 1, 2021, was also immaterial.

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

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

DISPOSITION
Athabasca Regional Oil Sands System
On October 5, 2022, we closed the sale of an 11.6% non-operating interest in seven pipelines in the Athabasca region of northern Alberta from our Regional Oil Sands System to Athabasca Indigenous Investments Limited Partnership (Aii), an entity representing 23 First Nation and Métis communities, for total consideration of approximately $1.1 billion. No gain or loss was recognized on the sale and a noncontrolling interest was recorded in our Consolidated Statements of Financial Position beginning in 2022 to reflect the interest held by Aii *(Note 19)*.

Subsequent to the sale, we maintained an 88.4% controlling interest in these assets, which are a component of our Liquids Pipelines segment, and continue to manage, operate and provide administrative services to them.

9. OTHER CURRENT ASSETS

December 31,	**2024**	2023
(millions of Canadian dollars)		
Derivative assets *(Note 23)*	**557**	623
Regulatory assets *(Note 7)*	**472**	470
Gas imbalances	**517**	209
Income taxes receivable	**375**	347
Other	**849**	791
	2,770	2,440

10. INVENTORY

December 31,	**2024**	2023
(millions of Canadian dollars)		
Natural gas	**811**	938
Crude oil	**479**	413
Other	**198**	128
	1,488	1,479

11. PROPERTY, PLANT AND EQUIPMENT

December 31,	Weighted Average Depreciation Rate	2024	2023
(millions of Canadian dollars)			
Pipelines	2.9%	**73,633**	66,698
Facilities and equipment	3.2%	**43,439**	37,634
Land and right-of-way[1]	2.8%	**4,181**	3,600
Gas mains, services and other	3.0%	**26,925**	15,346
Storage	2.6%	**6,455**	4,929
Wind turbines, solar panels and other	3.9%	**4,798**	4,511
Other	8.6%	**3,987**	1,652
Under construction	—%	**5,648**	2,829
Total property, plant and equipment[2]		**169,066**	137,199
Total accumulated depreciation[2]		**(37,962)**	(32,558)
Property, plant and equipment, net		**131,104**	104,641

1 The measurement of weighted average depreciation rate excludes non-depreciable assets.
2 As at December 31, 2024, the cost and accumulated depreciation of leased assets accounted for as lessor operating leases was $5.3 billion and $2.3 billion, respectively (December 31, 2023 - $5.1 billion and $2.1 billion, respectively).

Depreciation expense for the years ended December 31, 2024, 2023 and 2022 was $4.6 billion, $4.0 billion and $3.8 billion, respectively.

IMPAIRMENT

Chapman Ranch Wind Farm

Chapman Ranch Wind Farm (Chapman Ranch) is experiencing financial challenges associated with the original equipment integrity. As a result, we have recognized an impairment loss of $251 million for the year ended December 31, 2023, which is included in Impairment of long-lived assets in the Consolidated Statements of Earnings and is part of our Renewable Power Generation segment.

Magic Valley Wind Farm

In 2022, Magic Valley Wind Farm (Magic Valley) had commercial challenges caused by electricity transmission congestion and a negative price differential arising from higher transmission costs resulting in a lower electricity sale price. As a result, we recognized an impairment loss of $227 million for the year ended December 31, 2022, which is included in Impairment of long-lived assets in the Consolidated Statements of Earnings and is part of our Renewable Power Generation segment.

Bakken Pipeline System

For the year ended December 31, 2022, we recognized an impairment loss of $183 million on the US and Canadian components of the interstate pipeline transportation system within the North Dakota System of our Bakken Pipeline System in connection with the expiration of certain long-term take-or-pay contracts in 2023. This loss is included in Impairment of long-lived assets in the Consolidated Statements of Earnings and is part of our Liquids Pipelines segment.

Impairment charges were based on the amount by which the carrying value of the assets exceeded fair value, determined using expected discounted future cash flows.

12. VARIABLE INTEREST ENTITIES

CONSOLIDATED VARIABLE INTEREST ENTITIES

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

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

December 31,	**2024**	2023
(millions of Canadian dollars)		
Assets		
Current assets		
Cash and cash equivalents	**448**	442
Restricted cash	**11**	9
Trade receivables and unbilled revenues	**138**	144
Other current assets	**5**	8
Accounts receivable from affiliates	**13**	5
Inventory	**13**	11
	628	619
Property, plant and equipment, net	**6,934**	7,105
Long-term investments	**20**	14
Restricted long-term investments and cash	**141**	106
Deferred amounts and other assets	**145**	148
Intangible assets, net	**77**	84
	7,945	8,076
Liabilities		
Current liabilities		
Trade payables and accrued liabilities	**108**	83
Other current liabilities	**124**	145
Accounts payable to affiliates	**22**	4
	254	232
Long-term debt	**—**	1
Other long-term liabilities	**1,133**	971
Deferred income taxes	**6**	5
	1,393	1,209
	6,552	6,867

We do not have obligations to provide additional financial support to any of our consolidated VIEs.

UNCONSOLIDATED VARIABLE INTEREST ENTITIES

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

The carrying amount of these VIEs and our estimated maximum exposure to loss as at December 31, 2024 and 2023 are as follows:

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

December 31, 2023	Carrying Amount of the VIE	Maximum Exposure to Loss
(millions of Canadian dollars)		
Aux Sable Liquid Products L.P.[5]	105	130
Rampion Offshore Wind Limited[1]	391	452
Vector Pipeline[2]	191	320
Woodfibre LNG Limited Partnership[3]	778	2,854
Fox Squirrel Solar LLC[6]	312	661
Other[3]	132	230
	1,909	4,647

1 *As at December 31, 2024 and 2023, our maximum exposure to loss includes parental guarantees that have been committed in project contracts in which we would be liable for in the event of default by the VIE and the carrying value of an affiliate dividend receivable of $73 million and nil, respectively.*

2 *Includes Vector Pipeline Limited Partnership in Canada and Vector Pipeline L.P. in the US. As at December 31, 2024 and 2023, our maximum exposure to loss includes the carrying value of outstanding affiliate loans receivable of $16 million and $24 million, respectively, and our share of the VIE's available credit facility for $105 million.*

3 *As at December 31, 2024 and 2023, our maximum exposure to loss includes parental guarantees and funding obligations that have been committed in connection with the projects for which we would be liable in the event of default by the VIE(s).*

4 *In May 2024, Enbridge formed a joint venture (the Whistler Parent JV) in which we hold a 19.0% interest. Refer to* Note 13 - Long-Term Investments. *As at December 31, 2024, our maximum exposure to loss includes funding obligations that have been committed in project contracts in which we would be liable for in the event of default by the VIE.*

5 *In April 2024, Enbridge sold its interest in Aux Sable Liquid Products L.P. Refer to* Note 13 - Long-Term Investments. *As at December 31, 2023, our maximum exposure to loss included a guarantee by us for our respective share of the VIE's borrowing on a bank credit facility.*

6 *In November 2023, Enbridge acquired a 50.0% interest in Fox Squirrel Solar LLC. Refer to* Note 13 - Long-Term Investments. *As at December 31, 2024, Fox Squirrel Solar LLC no longer met the requirements of a VIE as a result of a VIE reconsideration event. As at December 31, 2023, our maximum exposure to loss included parental guarantees that had been committed in project contracts in which we would be liable for in the event of default by the VIE.*

We do not have an obligation to and did not provide any additional financial support to our unconsolidated VIEs during the years ended December 31, 2024 and 2023.

13. LONG-TERM INVESTMENTS

December 31,	Ownership Interest	2024	2023
(millions of Canadian dollars)			
EQUITY INVESTMENTS			
Liquids Pipelines			
Cactus II Pipeline LLC	30.0%	**651**	618
DCP Midstream, LLC (Class B Units)[1]	90.0%	**1,554**	1,486
Illinois Extension Pipeline Company, L.L.C.	65.0%	**608**	584
MarEn Bakken Company LLC[2]	75.0%	**2,296**	1,819
Seaway Crude Holdings LLC	50.0%	**2,820**	2,661
Other	30.0% - 43.8%	**96**	84
Gas Transmission			
Alliance Pipeline[3,5]	50.0%	**—**	359
Aux Sable[4,5]	42.7% - 50.0%	**—**	229
DCP Midstream, LLC (Class A Units)[6]	23.4%	**480**	367
Delaware Basin Residue, LLC[7]	15.0%	**319**	—
Gulfstream Natural Gas System, L.L.C.	50.0%	**1,316**	1,224
NEXUS Gas Transmission, LLC	50.0%	**1,301**	1,220
Sabal Trail Transmission, LLC	50.0%	**1,565**	1,467
Southeast Supply Header, LLC	50.0%	**355**	80
Steckman Ridge, LP	50.0%	**101**	87
Vector Pipeline	60.0%	**193**	191
Whistler Parent JV[8]	19.0%	**1,102**	—
Woodfibre LNG Limited Partnership	30.0%	**1,275**	777
Offshore - various joint ventures	22.0% - 74.3%	**260**	217
Other	21.3% - 45.0%	**49**	—
Gas Distribution and Storage			
Other	17.0% - 50.0%	**67**	22
Renewable Power Generation			
East-West Tie Limited Partnership	24.1%	**106**	132
EIH S.à r.l.[9]	51.0%	**89**	52
Fox Squirrel Solar LLC	50.0%	**783**	312
Hohe See and Albatros Offshore Wind Facilities	49.9%	**1,606**	1,701
Rampion Offshore Wind Limited	24.9%	**387**	391
Other	16.4% - 50.0%	**93**	110
OTHER LONG-TERM INVESTMENTS			
Gas Transmission			
Ara Divert HoldCo, Inc.		**116**	106
Other		**23**	22
Gas Distribution and Storage			
Other		**27**	24
Renewable Power Generation			
Other		**21**	21
Eliminations and Other			
Other[10]		**1,032**	430
		20,691	16,793

1 We own 90.0% of the Class B units of DCP Midstream, LLC. This class of units represents DCP Midstream, LLC's 65.0% interest in Gray Oak Pipeline, LLC (Gray Oak), resulting in a 58.5% interest in Gray Oak through DCP Midstream, LLC. On January 9, 2023, we acquired an additional 10.0% direct interest in Gray Oak for cash consideration of $230 million (US$172 million), bringing our effective interest to 68.5%.

2 MarEn Bakken Company LLC owns a 49.0% interest in Bakken Pipeline Investments LLC. Bakken Pipeline Investments LLC owns 75.0% of the Bakken Pipeline System, resulting in a 27.6% effective interest in the Bakken Pipeline System by us.

3 Includes Alliance Pipeline Limited Partnership in Canada and Alliance Pipeline L.P. in the US.

4 Includes Aux Sable Canada LP in Canada and Aux Sable Liquid Products L.P. and Aux Sable Midstream LLC in the US.
5 On April 1, 2024, we closed the sale of our 50.0% equity interest in the Alliance Pipeline and our interest in Aux Sable to Pembina Pipeline Corporation for $3.1 billion, including $0.3 billion of non-recourse debt.
6 We own 23.4% of the Class A units of DCP Midstream, LLC. These units represent DCP Midstream, LLC's 56.5% interest in DCP Midstream, LP (DCP), resulting in a 13.2% effective interest in DCP by us.
7 On October 31, 2024, we acquired an effective 15.0% interest in Delaware Basin Residue, LLC (DBR) for consideration of $303 million (US$220 million). DBR owns transportation and storage assets in West Texas, serving as the primary supply point for the Whistler Pipeline.
8 On May 29, 2024, we formed a joint venture with WhiteWater/I Squared Capital and MPLX LP. We hold a 19.0% interest in the joint venture, which owns a 100% interest in the Rio Bravo Pipeline project. Additionally, we have a 25.0% special interest in the Rio Bravo Pipeline project, resulting in a 39.3% effective interest in the Rio Bravo Pipeline project by us.
9 Owns a 50.0% interest in Éolien Maritime France SAS (EMF). Through our investment in EMF, we own equity interests in three French offshore wind projects, including effective interests in Saint-Nazaire (25.5%), Fécamp (17.9%) and Calvados (21.7%).
10 Consists of investments in exchange-traded funds and debt securities held by our wholly-owned captive insurance subsidiaries. Refer to Note 23 - Risk Management and Financial Instruments*.*

Equity investments include the unamortized excess of the purchase price over the underlying net book value of the investees' assets at the purchase date. As at December 31, 2024, this basis difference was $3.7 billion (2023 - $3.5 billion), of which $1.7 billion (2023 - $1.7 billion) was amortizable.

For the years ended December 31, 2024, 2023 and 2022, distributions received from equity investments were $2.9 billion, $3.1 billion and $2.6 billion, respectively.

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

Year ended December 31,	**2024**	2023	2022
(millions of Canadian dollars)			
Operating revenues	**20,657**	22,586	30,026
Operating expenses	**14,692**	17,111	23,835
Earnings	**5,177**	4,818	5,123
Earnings attributable to Enbridge	**2,304**	1,816	2,056

December 31,	**2024**	2023
(millions of Canadian dollars)		
Current assets	**8,611**	5,842
Non-current assets	**69,381**	61,141
Current liabilities	**7,240**	6,194
Non-current liabilities	**27,491**	23,957
Noncontrolling interests	**4,979**	4,124

DISPOSITION

Disposition of Alliance Pipeline and Aux Sable Interests

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

OTHER EQUITY INVESTMENT TRANSACTIONS

Joint Venture with WhiteWater/I Squared and MPLX

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

In connection with the formation of the Whistler Parent JV, we contributed our 100% interest in the Rio Bravo Pipeline project and $487 million (US$357 million) of cash to the Whistler Parent JV. In addition to our 19.0% equity interest in the Whistler Parent JV, we received a special equity interest in the Whistler Parent JV which provides for a 25.0% economic interest in the Rio Bravo Pipeline project. This interest is subject to certain redemption rights held by Whitewater/I Squared and MPLX. After the closing on May 29, 2024, we accrued for our share of the post-closing mandatory capital expenditures of approximately US$150 million for the Rio Bravo Pipeline project. Additional capital expenditures to complete the Rio Bravo Pipeline project will be proportionate to our economic interest.

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

Fox Squirrel Solar LLC

On November 15, 2023, we acquired a 50.0% interest in a newly formed partnership with EDF Renewables North America to participate in the initial phase of a solar power facility in Ohio. Cash consideration included an upfront payment of $157 million (US$115 million) with subsequent capital contributions of $591 million (US$426 million), for all phases of construction, made at the project's in-service dates.

Hohe See and Albatros Offshore Wind Facilities

On November 3, 2023, we acquired an additional 24.45% interest in the Hohe See Offshore Wind Facilities and Albatros Offshore Wind Facilities (the Offshore Wind Facilities), through the acquisition of a 49.0% interest in Enbridge Renewable Infrastructure Investments S.à r.l (ERII), for $391 million (€267 million) of cash and assumed debt of $524 million (€358 million), bringing our interest in the Offshore Wind Facilities to 49.9%. The Hohe See Offshore Wind Facilities and Albatros Offshore Wind Facilities are located approximately 100 kilometers off the northern coast of Germany and came into service in 2019 and 2020, respectively. Subsequent to the purchase, our interest in ERII is consolidated and our interest in the Offshore Wind Facilities will continue to be accounted for as an equity method investment included in the Renewable Power Generation segment.

DCP Midstream, LLC
On August 17, 2022, we completed a joint venture merger transaction with Phillips 66 resulting in a single joint venture, DCP Midstream, LLC, holding both our and Phillips 66's indirect ownership interests in Gray Oak and DCP. Our ownership in DCP Midstream, LLC consists of Class A and Class B Interests which track to our investments in DCP, included in the Gas Transmission segment, and Gray Oak, included in the Liquids Pipelines segment, respectively. Through our investment in DCP Midstream, LLC, we increased our effective economic interest in Gray Oak to 58.5% from 22.8% and reduced our effective economic interest in DCP to 13.2% from 28.3%. As a result of the transaction, Enbridge assumed operatorship of Gray Oak in the second quarter of 2023.

We determined the fair value of our decrease in economic interest in DCP based on the unadjusted quoted market price of DCP's publicly traded common units on the transaction closing date. The fair value of our increased economic interest in Gray Oak was determined using the fair value prescribed to the change in our economic interest in DCP. As a result of the merger transaction and the realignment of our economic interests in DCP and Gray Oak, we also received cash consideration of approximately $522 million (US$404 million) and recorded an accounting gain of $1.1 billion (US$832 million) to Gain on joint venture merger transaction in the Consolidated Statements of Earnings. Both DCP and Gray Oak continue to be accounted for as equity method investments.

14. INTANGIBLE ASSETS

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

December 31, 2023	Weighted Average Amortization Rate	Cost	Accumulated Amortization	Net
(millions of Canadian dollars)				
Software	12.0%	1,921	(1,090)	831
Power purchase agreements	4.3%	58	(24)	34
Project agreement[1]	4.0%	158	(41)	117
Customer relationships	8.6%	2,636	(675)	1,961
Other intangible assets	8.2%	603	(185)	418
Under development	—%	176	—	176
		5,552	(2,015)	3,537

1 Represents a project agreement acquired from the merger of Enbridge and Spectra Energy.

For the years ended December 31, 2024, 2023 and 2022, our amortization expense related to intangible assets totaled $530 million, $535 million and $483 million, respectively. Our expected amortization expense associated with existing intangible assets for each of the years 2025 to 2029 is $558 million.

15. GOODWILL

	Liquids Pipelines	Gas Transmission	Gas Distribution and Storage	Renewable Power Generation	Consolidated
(millions of Canadian dollars)					
Balance at January 1, 2023	8,549	18,106	5,397	388	32,440
Foreign exchange and other	(205)	(425)	—	(8)	(638)
Acquisition[3]	—	46	—	—	46
Balance at December 31, 2023[1,2]	8,344	17,727	5,397	380	31,848
Dispositions[4]	**—**	**(1,026)**	**—**	**—**	**(1,026)**
Foreign exchange and other	**672**	**1,354**	**204**	**34**	**2,264**
Acquisitions[5]	**—**	**223**	**3,291**	**—**	**3,514**
Balance at December 31, 2024[1,2]	**9,016**	**18,278**	**8,892**	**414**	**36,600**

1 *Gross goodwill as at December 31, 2024 and 2023 was $40.7 billion and $35.9 billion, respectively.*
2 *Accumulated impairment as at December 31, 2024 and 2023 was $4.1 billion.*
3 *In 2023, we recorded $46 million of goodwill related to the acquisition of Aitken Creek. Refer to* Note 8 - Acquisitions and Disposition.
4 *In 2024, we derecognized $1.0 billion of goodwill related to the sale of our interests in the Alliance Pipeline and Aux Sable. Refer to* Note 13 - Long-Term Investments.
5 *In 2024, we recorded $895 million of goodwill related to the PSNC Acquisition, $793 million of goodwill related to the Questar Acquisition, $1.6 billion of goodwill related to the EOG Acquisition, and $223 million of goodwill related to the RNG Facilities Acquisition. Refer to* Note 8 - Acquisitions and Disposition.

16. OTHER CURRENT LIABILITIES

December 31,	**2024**	2023
(millions of Canadian dollars)		
Dividends payable	**2,088**	1,975
Deferred credits	**1,072**	1,177
Derivative liabilities *(Note 23)*	**1,335**	738
Taxes payable	**959**	596
Regulatory liabilities *(Note 7)*	**616**	307
Federal carbon program liability	**498**	376
Asset retirement obligations *(Note 18)*	**120**	136
Other	**553**	354
	7,241	5,659

17. DEBT

December 31,	Weighted Average Interest Rate[8]	Maturity	**2024**	2023
(millions of Canadian dollars)				
Enbridge Inc.				
US dollar senior notes	4.8%	2025 - 2054	**19,703**	14,636
Medium-term notes	4.5%	2025 - 2064	**9,900**	8,598
Sustainability-linked bonds	4.7%	2032 - 2033	**7,146**	6,751
Fixed-to-fixed subordinated term notes[1]	7.4%	2054 - 2084	**9,372**	7,156
Fixed-to-floating rate subordinated term notes[2]	5.8%	2077 - 2078	**6,139**	5,828
Floating rate notes			**—**	791
Fixed-to-floating non-call notes			**—**	923
Commercial paper and credit facility draws	3.7%	2025 - 2029	**5,843**	3,177
Other[3]			**12**	17
Enbridge (U.S.) Inc.				
Commercial paper and credit facility draws	4.8%	2026 - 2029	**4,707**	670
Other[3]			**276**	263
Enbridge Energy Partners, L.P.				
Senior notes	6.5%	2025 - 2045	**3,524**	3,231
Enbridge Gas Inc.				
Medium-term notes	4.1%	2025 - 2053	**9,970**	10,185
Debentures	8.7%	2025	**125**	210
Commercial paper and credit facility draws	3.4%	2026	**530**	400
Other[3]			**1**	2
Enbridge Pipelines (Southern Lights) L.L.C.				
Senior notes	4.0%	2040	**736**	791
Enbridge Pipelines Inc.				
Medium-term notes[4]	4.2%	2025 - 2053	**5,425**	5,425
Debentures			**—**	200
Commercial paper and credit facility draws	3.8%	2026	**509**	449
Other[3]			**2**	4
Enbridge Southern Lights LP				
Senior notes	4.0%	2040	**183**	214
Spectra Energy Capital, LLC				
Senior notes	7.1%	2032 - 2038	**248**	228
Algonquin Gas Transmission, LLC				
Senior notes	4.4%	2029 - 2034	**1,222**	1,121
East Tennessee Natural Gas, LLC				
Senior notes	5.7%	2034	**662**	251
Texas Eastern Transmission, LP				
Senior notes	4.7%	2028 - 2048	**3,667**	3,362
Spectra Energy Partners, LP				
Senior notes	4.2%	2025 - 2045	**3,164**	4,220
Blauracke GmbH				
Senior notes	2.1%	2032	**471**	521
The East Ohio Gas Company				
Senior notes	3.1%	2025 - 2052	**3,308**	—
Other[3]			**24**	—
Questar Gas Company				
Senior notes	4.2%	2027 - 2052	**2,028**	—
Public Service Company of North Carolina, Incorporated				
Senior notes	5.0%	2026 - 2054	**1,798**	—
Enbridge Holdings (Tomorrow RNG), LLC				
Senior notes	4.9%	2025	**817**	—
Westcoast Energy Inc.				
Medium-term notes	5.4%	2025 - 2041	**875**	1,225
Debentures	8.1%	2025 - 2026	**275**	275
Fair value adjustment			**(468)**	514
Other[5]			**(522)**	(439)
Total debt[6]			**101,672**	81,199
Current maturities			**(7,729)**	(6,084)
Short-term borrowings[7]			**(529)**	(400)
Long-term debt			**93,414**	74,715

1 For an initial five, 5.5, 9.75 or 10 years, the notes carry a fixed interest rate. Subsequently, during each reset period the interest rate will be reset to equal to the Five-Year US Treasury rate or Five-Year Government of Canada bond yield plus a margin. The notes would be converted automatically into Conversion Preference Shares in the event of bankruptcy and related events.
2 For an initial five or 10 years, the notes carry a fixed interest rate. Subsequently, the interest rate will be floating and set to equal to the Canadian Dollar Offered Rate or the Secured Overnight Financing Rate (SOFR) plus a margin. The notes would be converted automatically into Conversion Preference Shares in the event of bankruptcy and related events.
3 Primarily finance lease obligations.
4 Included in medium-term notes is $100 million with a maturity date of 2112.
5 Primarily unamortized discounts, premiums and debt issuance costs.
6 2024 - $40 billion, US$43 billion and €316 million; 2023 - $37 billion, US$33 billion and €359 million. Totals exclude capital lease obligations, unamortized discounts, premiums and debt issuance costs and fair value adjustment.
7 Weighted average interest rates on outstanding commercial paper were 3.4% as at December 31, 2024 (2023 - 5.2%).
8 Calculated based on term notes, debentures, commercial paper and credit facility draws outstanding as at December 31, 2024.

As at December 31, 2024, all outstanding debt was unsecured.

CREDIT FACILITIES

The following table provides details of our committed credit facilities as at December 31, 2024:

	Maturity[1]	Total Facilities	Draws[2]	Available
(millions of Canadian dollars)				
Enbridge Inc.	2025-2049	**8,840**	**5,843**	**2,997**
Enbridge (U.S.) Inc.	2026-2029	**10,813**	**4,707**	**6,106**
Enbridge Pipelines Inc.	2026	**2,000**	**509**	**1,491**
Enbridge Gas Inc.	2026	**2,500**	**530**	**1,970**
Total committed credit facilities		**24,153**	**11,589**	**12,564**

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 March 2024, we entered into a delayed-draw term loan facility in support of sustainable retrofit projects for large buildings using decarbonization solutions for $200 million which matures in March 2049.

In June 2024, we entered into a five-year, non-revolving term loan facility of US$250 million which matures in June 2029.

In July 2024, we renewed approximately $8.8 billion of our 364-day extendible credit facilities, extending the maturity dates to July 2026, which includes a one-year term out provision from July 2025. We also renewed approximately $7.8 billion of our five-year credit facilities, extending the maturity dates to July 2029. Further, we extended the maturity dates of our three-year credit facilities to July 2027.

In July 2024, Enbridge Gas Ontario extended the maturity date of its 364-day extendible credit facility to July 2026, which includes a one-year term out provision from July 2025.

In July 2024, Enbridge Pipelines Inc. extended the maturity date of its 364-day extendible credit facility to July 2026, which includes a one-year term out provision from July 2025.

In January 2024 and October 2024, we entered into new letters of credit facilities and increased our letter of credit facilities by $146 million and $200 million, respectively.

In addition to the committed credit facilities noted above, we maintain $1.4 billion of uncommitted demand letter of credit facilities, of which $931 million was unutilized as at December 31, 2024. As at December 31, 2023, we had $1.1 billion of uncommitted demand letter of credit facilities, of which $572 million was unutilized.

Our credit facilities carry a weighted average standby fee of 0.1% per annum on the unused portion and draws bear interest at market rates. Certain credit facilities serve as a back-stop to the commercial paper programs and we have the option to extend such facilities, which are currently scheduled to mature from 2025 to 2049.

As at December 31, 2024 and 2023, commercial paper and credit facility draws, net of short-term borrowings and non-revolving credit facilities that mature within one year, of $10.3 billion and $3.8 billion, respectively, were supported by the availability of long-term committed credit facilities and, therefore, have been classified as long-term debt.

ACQUISITIONS

As a result of the EOG Acquisition, RNG Facilities Acquisition, Questar Acquisition and PSNC Acquisition, our debt increased by US$1.9 billion, US$568 million, US$1.0 billion, and US$1.1 billion, respectively, on each acquisition date. Refer to *Note 8 - Acquisitions and Disposition* for further details.

LONG-TERM DEBT ISSUANCES

During the year ended December 31, 2024, we completed the following long-term debt issuances totaling US$5.7 billion and $1.8 billion:

Company	Issue Date			Principal Amount
(millions of Canadian dollars, unless otherwise stated)				
Enbridge Inc.				
	April 2024	5.25%	senior notes due April 2027	US$750
	April 2024	5.30%	senior notes due April 2029	US$750
	April 2024	5.63%	senior notes due April 2034	US$1,200
	April 2024	5.95%	senior notes due April 2054	US$800
	June 2024	7.38%	fixed-to-fixed subordinated notes due March 2055[1]	US$500
	June 2024	7.20%	fixed-to-fixed subordinated notes due June 2054[2]	US$700
	August 2024	4.21%	medium-term notes due February 2030	$600
	August 2024	4.73%	medium-term notes due August 2034	$800
	August 2024	5.32%	medium-term notes due August 2054	$400
Algonquin Gas Transmission, LLC				
	July 2024	5.95%	senior notes due July 2034	US$350
East Tennessee Natural Gas, LLC				
	December 2024	5.72%	senior notes due December 2034	US$460
Questar Gas Company				
	December 2024	5.33%	senior notes due December 2034	US$200

1 For the initial 5.5 years, the notes carry a fixed interest rate. On March 15, 2030, the interest rate will be reset to equal the Five-Year US Treasury rate plus a margin of 3.12%.

2 For the initial 9.75 years, the notes carry a fixed interest rate. On June 27, 2034, the interest rate will be reset to equal the Five-Year US Treasury rate plus a margin of 2.97%.

LONG-TERM DEBT REPAYMENTS

During the year ended December 31, 2024, we completed the following long-term debt repayments totaling US$3.9 billion, $1.4 billion, and €43 million, respectively:

Company	Repayment Date		Principal Amount
(millions of Canadian dollars, unless otherwise stated)			
Enbridge Inc.			
	February 2024	Floating rate notes[1]	US$600
	February 2024	2.15% senior notes	US$400
	March 2024	5.97% senior notes[2]	US$700
	June 2024	3.50% senior notes	US$500
	November 2024	3.95% medium-term notes	$500
Enbridge Gas Inc.			
	August 2024	3.15% medium-term notes	$215
	December 2024	9.85 % debentures	$85
Enbridge Pipelines (Southern Lights) L.L.C.			
	June and December 2024	3.98% senior notes	US$89
Enbridge Pipelines Inc.			
	February 2024	8.20% debentures	$200
Enbridge Southern Lights LP			
	January, July and December 2024	4.01% senior notes	$31
Westcoast Energy Inc.			
	September 2024	3.43% medium-term notes	$350
Spectra Energy Partners, LP			
	March 2024	4.75% senior notes	US$1,000
Blauracke GmbH			
	April and October 2024	2.10% senior notes	€43
Algonquin Gas Transmission, LLC			
	July 2024	3.51% senior notes	US$350
Questar Gas Company			
	December 2024	2.98% senior notes	US$40
East Tennessee Natural Gas, LLC			
	December 2024	3.10% senior notes	US$190

1 Notes carried an interest rate set to equal the SOFR plus a margin of 63 basis points.
2 The notes carried an original maturity date in March 2026, and were callable in March 2024, which was one year after their issuance.

DEBT COVENANTS

Our credit facility agreements and term debt indentures include standard events of default and covenant provisions whereby accelerated repayment and/or termination of the agreements may result if we were to default on payment or violate certain covenants. As at December 31, 2024, we were in compliance with all debt covenants.

ANNUAL DEBT MATURITIES

As at December 31, 2024, we have commitments as detailed below:

	Total	Less than 1 year	2 years	3 years	4 years	5 years	Thereafter
(millions of Canadian dollars)							
Annual debt maturities[1]	101,819	7,724	7,379	4,704	3,056	13,578	65,378

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

INTEREST EXPENSE

Year ended December 31,	**2024**	2023	2022
(millions of Canadian dollars)			
Debentures and term notes	**4,123**	3,439	2,910
Commercial paper and credit facility draws	**439**	519	388
Amortization of fair value adjustment	**18**	(45)	(45)
Capitalized interest	**(161)**	(101)	(74)
	4,419	3,812	3,179

18. ASSET RETIREMENT OBLIGATIONS

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

The discount rates used to estimate the present value of the expected future cash flows for the years ended December 31, 2024 and 2023 ranged from 1.5% to 9.0%.

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

December 31,	**2024**	2023
(millions of Canadian dollars)		
Obligations at beginning of year	**493**	488
Liabilities acquired	**185**	1
Liabilities incurred	**3**	—
Liabilities settled	**(139)**	(23)
Change in estimate and other	**51**	5
Foreign currency translation adjustment	**40**	(6)
Accretion expense	**33**	28
Obligations at end of year	**666**	493
Presented as follows:		
Other current liabilities *(Note 16)*	**120**	136
Other long-term liabilities	**546**	357
	666	493

19. NONCONTROLLING INTERESTS

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

December 31,	**2024**	2023
(millions of Canadian dollars)		
Algonquin Gas Transmission, LLC	**414**	384
Enbridge Athabasca Midstream Investor Limited Partnership	**1,073**	1,086
Maritimes & Northeast Pipeline, L.L.C.	**606**	559
Renewable energy assets	**786**	885
Maritimes & Northeast Pipeline Limited Partnership	**109**	111
Other	**5**	4
	2,993	3,029

20. SHARE CAPITAL

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

COMMON SHARES

	2024		2023		2022	
December 31,	Number of Shares	Amount	Number of Shares	Amount	Number of Shares	Amount
(millions of Canadian dollars; number of shares in millions)						
Balance at beginning of year	**2,125**	**69,180**	2,025	64,760	2,026	64,799
Shares issued, net of issue costs	**51**	**2,489**	103	4,485	—	—
Shares issued on exercise of stock options	**1**	**39**	—	3	2	53
Shares issued on vesting of RSUs, net of tax	**1**	**30**	—	12	—	—
Share repurchases at stated value[1]	**—**	**—**	(3)	(80)	(3)	(88)
Other	**—**	**—**	—	—	—	(4)
Balance at end of year	**2,178**	**71,738**	2,125	69,180	2,025	64,760

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

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

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

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

PREFERENCE SHARES

December 31,	2024 Number of Shares	2024 Amount	2023 Number of Shares	2023 Amount	2022 Number of Shares	2022 Amount
(millions of Canadian dollars; number of shares in millions)						
Preference Shares, Series A	**5**	**125**	5	125	5	125
Preference Shares, Series B	**20**	**500**	20	500	20	500
Preference Shares, Series D	**18**	**450**	18	450	18	450
Preference Shares, Series F	**18**	**454**	18	454	20	500
Preference Shares, Series G[1]	**2**	**46**	2	46	—	—
Preference Shares, Series H	**12**	**291**	12	291	14	350
Preference Shares, Series I[2]	**2**	**59**	2	59	—	—
Preference Shares, Series L	**16**	**411**	16	411	16	411
Preference Shares, Series N	**18**	**450**	18	450	18	450
Preference Shares, Series P	**16**	**400**	16	400	16	400
Preference Shares, Series R	**16**	**400**	16	400	16	400
Preference Shares, Series 1	**16**	**411**	16	411	16	411
Preference Shares, Series 3	**22**	**562**	24	600	24	600
Preference Shares, Series 4[3]	**2**	**38**	—	—	—	—
Preference Shares, Series 5	**8**	**206**	8	206	8	206
Preference Shares, Series 7	**10**	**250**	10	250	10	250
Preference Shares, Series 9	**11**	**275**	11	275	11	275
Preference Shares, Series 11	**20**	**500**	20	500	20	500
Preference Shares, Series 13	**14**	**350**	14	350	14	350
Preference Shares, Series 15	**11**	**275**	11	275	11	275
Preference Shares, Series 19	**20**	**500**	20	500	20	500
Issuance costs		**(135)**		(135)		(135)
Balance at end of year		**6,818**		6,818		6,818

1 On June 1, 2023, 1,827,695 of the outstanding Preference Shares, Series F were converted into Preference Shares, Series G.
2 On September 1, 2023, 2,350,602 of the outstanding Preference Shares, Series H were converted into Preference Shares, Series I.
3 On September 1, 2024, 1,502,775 of the outstanding Preference Shares, Series 3 were converted into Preference Shares, Series 4.

Characteristics of our outstanding preference shares are as follows:

	Dividend Rate	Dividend[1]	Per Share Base Redemption Value[2]	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%	$1.30052	$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%	$1.38452	$25	June 1, 2028	Series G
Preference Shares, Series G[5]	6.15%	$1.51644	$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]	5.76%	$1.42028	$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[7]	5.92%	$1.47952	$25	March 1, 2029	Series Q
Preference Shares, Series R[8]	6.31%	$1.57852	$25	June 1, 2029	Series S
Preference Shares, Series 1	6.70%	US$1.67592	US$25	June 1, 2028	Series 2
Preference Shares, Series 3[9]	5.29%	$1.32200	$25	September 1, 2029	Series 4
Preference Shares, Series 4[10]	6.02%	$1.48440	$25	September 1, 2029	Series 3
Preference Shares, Series 5[11]	6.68%	US$1.67076	US$25	March 1, 2029	Series 6
Preference Shares, Series 7[12]	5.99%	$1.49700	$25	March 1, 2029	Series 8
Preference Shares, Series 9[13]	5.67%	$1.41800	$25	December 1, 2029	Series 10
Preference Shares, Series 11	3.94%	$0.98452	$25	March 1, 2025	Series 12
Preference Shares, Series 13	3.04%	$0.76076	$25	June 1, 2025	Series 14
Preference Shares, Series 15	2.98%	$0.74576	$25	September 1, 2025	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. These Dividend Rates are presented in the table above on an annualized basis using the most recent quarterly dividend rate reset. 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 $0.37911 from $0.43014 on December 1, 2024 due to reset on a quarterly basis.

6 The quarterly dividend per share paid on Preference Shares, Series I was decreased to $0.35507 from $0.40589 on December 1, 2024 due to reset on a quarterly basis.

7 The quarterly dividend per share paid on Preference Shares, Series P was increased to $0.36988 from $0.27369 on March 1, 2024 due to reset of the annual dividend on March 1, 2024.

8 The quarterly dividend per share paid on Preference Shares, Series R was increased to $0.39463 from $0.25456 on June 1, 2024 due to reset of the annual dividend on June 1, 2024.

9 The quarterly dividend per share paid on Preference Shares, Series 3 was increased to $0.33050 from $0.23356 on September 1, 2024 due to reset of the annual dividend on September 1, 2024.

10 On September 1, 2024, 1,502,775 of the outstanding Preference Shares, Series 3 were converted into Preference Shares, Series 4. The quarterly dividend per share paid on Preference Shares, Series 4 was decreased to $0.37110 from $0.42206 on December 1, 2024 due to reset on a quarterly basis following the date of issuance.

11 The quarterly dividend per share paid on Preference Shares, Series 5 was increased to US$0.41769 from US$0.33596 on March 1, 2024 due to reset of the annual dividend on March 1, 2024.

12 The quarterly dividend per share paid on Preference Shares, Series 7 was increased to $0.37425 from $0.27806 on March 1, 2024 due to reset of the annual dividend on March 1, 2024.

13 The quarterly dividend per share paid on Preference Shares, Series 9 was increased to $0.35450 from $0.25606 on December 1, 2024 due to reset of the annual dividend on December 1, 2024.

SHAREHOLDER RIGHTS PLAN

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

21. STOCK OPTION AND STOCK UNIT PLANS

We maintain three primary vehicles under our long-term incentive plan (the Plan): ISOs, PSUs and RSUs. Total stock-based compensation expense recorded for the years ended December 31, 2024, 2023 and 2022 was $186 million, $154 million and $260 million, respectively. The number of common shares authorized for share-settled awards under the Plan was 181 million as at December 31, 2024, 2023 and 2022.

INCENTIVE STOCK OPTIONS

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

December 31, 2024	Number	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life *(years)*	Aggregate Intrinsic Value
(number of options in thousands; weighted average exercise price in Canadian dollars; intrinsic value in millions of Canadian dollars)				
Options outstanding at beginning of year	**28,729**	**50.79**		
Options granted	**5,036**	**46.36**		
Options exercised[1]	**(7,328)**	**49.27**		
Options cancelled or expired	**(1,113)**	**51.78**		
Options outstanding at end of year	**25,324**	**50.31**	**5.7**	**70**
Options vested at end of year[2]	**15,602**	**51.33**	**4.2**	**37**

1 The total intrinsic value of ISOs exercised during the years ended December 31, 2024, 2023 and 2022 was $18 million, $2 million and $66 million, respectively, and cash received on exercise was $1 million, nil and $3 million, respectively.

2 The total fair value of ISOs vested during the years ended December 31, 2024, 2023 and 2022 was $17 million, $20 million and $21 million, respectively.

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

Year ended December 31,	**2024**	2023	2022
Fair value per option *(Canadian dollars)*[1]	**4.07**	6.05	5.07
Valuation assumptions			
Expected option term *(years)*[2]	**6**	6	6
Expected volatility[3]	**21.1%**	22.2%	21.9%
Expected dividend yield[4]	**8.1%**	6.7%	6.5%
Risk-free interest rate[5]	**3.8%**	3.5%	1.8%

1 Options granted to US employees are based on the NYSE prices. The option value and assumptions shown are based on a weighted average of the US and Canadian options. The fair value per option for the years ended December 31, 2024, 2023 and 2022 were $3.53, $5.38 and $4.78, respectively, for Canadian employees and US$3.58, US$5.23 and US$4.62, respectively, for US employees.

2 The expected option term is six years based on historical exercise practice and five years for retirement eligible employees.

3 Expected volatility is determined with reference to historic daily share price volatility and consideration of the implied volatility observable in call option values near the grant date.

4 The expected dividend yield is the current annual dividend at the grant date divided by the current stock price.

5 The risk-free interest rate is based on the Government of Canada's Canadian bond yields and the US Treasury bond yields at the grant date.

Compensation expense recorded for the years ended December 31, 2024, 2023 and 2022 for ISOs was $19 million, $18 million and $15 million, respectively. As at December 31, 2024, unrecognized compensation expense related to non-vested ISOs was $12 million. The expense is expected to be fully recognized over a weighted average period of approximately two years.

PERFORMANCE STOCK UNITS

PSUs are granted to certain key employees where cash awards are paid following a three-year performance cycle. Awards are calculated by multiplying the number of units outstanding at the end of the performance period by Enbridge's weighted average share price for 20 days prior to the maturity of the grant and by a performance multiplier. The performance multiplier ranges from zero, if our performance fails to meet threshold performance levels, to a maximum of 2.0 if we perform within the highest range of the performance targets. The performance multiplier is derived through a calculation of our Total Shareholder Return percentile rank relative to a specified peer group of companies and our distributable cash flow per share, adjusted for unusual, infrequent or other non-operating factors, relative to targets established at the time of grant. Beginning with the 2023 grant, the performance multiplier also includes a greenhouse gas reduction component. To calculate the 2024 expense, a multiplier of 1.38 was used for 2024 PSU grants, 1.1 for 2023 PSU grants and 1.0 for 2022 PSU grants.

December 31, 2024	Number	Weighted Average Remaining Contractual Life *(years)*	Aggregate Intrinsic Value
(number of units in thousands; intrinsic value in millions of Canadian dollars)			
Units outstanding at beginning of year	**3,180**		
Units granted	**1,444**		
Units cancelled	**(104)**		
Units matured[1]	**(1,355)**		
Dividend reinvestment	**237**		
Units outstanding at end of year	**3,402**	**1.6**	**244**

1 The total amount paid during the years ended December 31, 2024, 2023 and 2022 for PSUs was $65 million, $123 million and $90 million, respectively.

Compensation expense recorded for the years ended December 31, 2024, 2023 and 2022 for PSUs was $75 million, $59 million and $169 million, respectively. As at December 31, 2024, unrecognized compensation expense related to non-vested PSUs was $109 million. The expense is expected to be fully recognized over a weighted average period of approximately two years.

RESTRICTED STOCK UNITS

Employees may also be granted cash-settled or share-settled RSUs under the Plan.Share-settled awards granted to non-executive senior management employees vest following a three-year maturity period. Beginning in 2023, share-settled units were also granted to non-executive employees. These units vest either on each of the first, second and third anniversaries of the grant date, or following a 12-month period. Cash-settled RSUs are given to non-executive employees and are paid in equal installments on each of the first, second and third anniversaries of the grant date.

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

December 31, 2024	Number	Weighted Average Grant Date Fair Value[2]	Weighted Average Remaining Contractual Life *(years)*	Aggregate Intrinsic Value
(number of units in thousands; intrinsic value in millions of Canadian dollars)				
Units outstanding at beginning of year	**3,571**	**50.69**		
Units granted	**1,758**	**48.50**		
Units cancelled	**(112)**	**51.38**		
Units matured[1]	**(1,910)**	**49.99**		
Dividend reinvestment	**284**	**50.94**		
Units outstanding at end of year	**3,591**	**51.10**	**1.0**	**187**

1 *The total amount paid during the years ended December 31, 2024, 2023 and 2022 for RSUs was $40 million, $56 million and $32 million, respectively.*

2 *Weighted average grant date fair value excludes cash-settled units.*

Compensation expense recorded for the years ended December 31, 2024, 2023 and 2022 for RSUs was $92 million, $77 million and $76 million, respectively. As at December 31, 2024, unrecognized compensation expense related to non-vested RSUs was $67 million. The expense is expected to be fully recognized over a weighted average period of approximately one year.

22. COMPONENTS OF ACCUMULATED OTHER COMPREHENSIVE INCOME/(LOSS)

Changes in AOCI attributable to our common shareholders for the years ended December 31, 2024, 2023 and 2022 are as follows:

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

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

	Cash Flow Hedges	Excluded Components of Fair Value Hedges	Net Investment Hedges	Cumulative Translation Adjustment	Equity Investees	Pension and OPEB Adjustment	Total
(millions of Canadian dollars)							
Balance as at January 1, 2022	(897)	—	(166)	56	(5)	(84)	(1,096)
Other comprehensive income/(loss) retained in AOCI	1,125	(35)	(971)	4,292	(6)	411	4,816
Other comprehensive (income)/loss reclassified to earnings							
Interest rate contracts[1]	186	—	—	—	—	—	186
Foreign exchange contracts[3]	(4)	—	—	—	—	—	(4)
Other contracts[5]	4	—	—	—	—	—	4
Amortization of pension and OPEB actuarial gain[4]	—	—	—	—	—	(14)	(14)
Other	—	—	—	—	16	—	16
	1,311	(35)	(971)	4,292	10	397	5,004
Tax impact							
Income tax on amounts retained in AOCI	(250)	—	—	—	—	(99)	(349)
Income tax on amounts reclassified to earnings	(43)	—	—	—	—	4	(39)
	(293)	—	—	—	—	(95)	(388)
Balance as at December 31, 2022	121	(35)	(1,137)	4,348	5	218	3,520

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

23. RISK MANAGEMENT AND FINANCIAL INSTRUMENTS

MARKET RISK

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

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

Foreign Exchange Risk

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

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

Interest Rate Risk
Our earnings, cash flows and OCI are exposed to short-term interest rate variability due to the regular repricing of our variable rate debt, primarily commercial paper. We have a policy of limiting our maximum floating rate debt to 30% of total debt outstanding. To ensure compliance with our policy, we monitor and adjust our debt portfolio mix of fixed and variable rate debt instruments in conjunction with the use of derivative instruments. We have implemented a program to partially mitigate the impact of short-term interest rate volatility on interest expense via the execution of floating-to-fixed interest rate swaps and costless collars. These swaps have an average fixed rate of 3.6%.

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

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

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

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

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

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

December 31, 2023	Derivative Instruments Used as Cash Flow Hedges	Derivative Instruments Used as Fair Value Hedges	Non-Qualifying Derivative Instruments	Total Gross Derivative Instruments as Presented	Amounts Available for Offset	Total Net Derivative Instruments
(millions of Canadian dollars)						
Other current assets						
Foreign exchange contracts	—	41	98	139	(32)	107
Interest rate contracts	31	—	34	65	(32)	33
Commodity contracts	—	—	418	418	(270)	148
Other contracts	—	—	1	1	(1)	—
	31	41	551	623	(335)	288
Deferred amounts and other assets						
Foreign exchange contracts	—	16	319	335	(122)	213
Interest rate contracts	51	—	2	53	(21)	32
Commodity contracts	—	—	75	75	(41)	34
	51	16	396	463	(184)	279
Other current liabilities						
Foreign exchange contracts	—	(44)	(84)	(128)	32	(96)
Interest rate contracts	(183)	—	(3)	(186)	32	(154)
Commodity contracts	(11)	—	(412)	(423)	270	(153)
Other contracts	—	—	(1)	(1)	1	—
	(194)	(44)	(500)	(738)	335	(403)
Other long-term liabilities						
Foreign exchange contracts	—	(17)	(481)	(498)	122	(376)
Interest rate contracts	(3)	—	(85)	(88)	21	(67)
Commodity contracts	(7)	—	(159)	(166)	41	(125)
	(10)	(17)	(725)	(752)	184	(568)
Total net derivative liability						
Foreign exchange contracts	—	(4)	(148)	(152)	—	(152)
Interest rate contracts	(104)	—	(52)	(156)	—	(156)
Commodity contracts	(18)	—	(78)	(96)	—	(96)
Other contracts	—	—	—	—	—	—
	(122)	(4)	(278)	(404)	—	(404)

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

	2024							2023
As at December 31,	2025	2026	2027	2028	2029	Thereafter	Total	Total
Foreign exchange contracts - US dollar forwards - purchase *(millions of US dollars)*	**1,245**	**—**	**—**	**—**	**—**	**—**	**1,245**	1,860
Foreign exchange contracts - US dollar forwards - sell *(millions of US dollars)*	**6,406**	**5,627**	**4,811**	**3,522**	**1,248**	**—**	**21,614**	24,747
Foreign exchange contracts - British pound (GBP) forwards - sell *(millions of GBP)*	**30**	**28**	**32**	**—**	**—**	**—**	**90**	120
Foreign exchange contracts - Euro forwards - sell *(millions of Euro)*	**126**	**121**	**81**	**67**	**66**	**129**	**590**	731
Foreign exchange contracts - Japanese yen forwards - purchase *(millions of yen)*	**84,800**	**—**	**—**	**—**	**—**	**—**	**84,800**	84,800
Interest rate contracts - short-term pay fixed rate *(millions of Canadian dollars)*	**2,296**	**1,737**	**676**	**49**	**13**	**—**	**4,771**	9,018
Interest rate contracts - short-term receive fixed rate *(millions of Canadian dollars)*	**—**	**—**	**—**	**—**	**—**	**—**	**—**	2,015
Interest rate contracts - long-term pay fixed rate *(millions of Canadian dollars)*[1]	**4,531**	**753**	**—**	**—**	**—**	**—**	**5,284**	5,162
Interest rate contracts - costless collar *(millions of Canadian dollars)*	**1,938**	**268**	**104**	**6**	**—**	**—**	**2,316**	1,139
Equity contracts *(millions of Canadian dollars)*	**—**	**—**	**—**	**—**	**—**	**—**	**—**	47
Commodity contracts - natural gas *(billions of cubic feet)*[2]	**154**	**79**	**37**	**11**	**5**	**2**	**288**	86
Commodity contracts - crude oil *(millions of barrels)*[2]	**6**	**15**	**1**	**1**	**1**	**1**	**25**	6
Commodity contracts - power *(megawatt per hour (MW/H))*	**61**	**24**	**(31)**	**(49)**	**(30)**	**—**	**(5)** [3]	(22) [3]

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

Derivatives Designated as Fair Value Hedges

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

Year ended December 31,	2024	2023
(millions of Canadian dollars)		
Unrealized loss on derivative	**(3)**	(132)
Unrealized gain on hedged item	**6**	131
Realized gain/(loss) on derivative	**26**	(47)
Realized loss on hedged item	**(79)**	—

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

Year ended December 31,	**2024**	2023	2022
(millions of Canadian dollars)			
Amount of unrealized gain/(loss) recognized in OCI			
Cash flow hedges			
Foreign exchange contracts	**—**	—	3
Interest rate contracts	**67**	201	1,151
Commodity contracts	**19**	68	(53)
Other contracts	**1**	(2)	(4)
Fair value hedges			
Foreign exchange contracts	**(42)**	15	(35)
	45	282	1,062
Amount of (income)/loss reclassified from AOCI to earnings			
Foreign exchange contracts[1]	**53**	—	13
Interest rate contracts[2]	**31**	28	186
Commodity contracts[3]	**(1)**	—	—
Other contracts[4]	**—**	—	4
	83	28	203

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

We estimate that no amounts from AOCI related to open cash flow hedges will be reclassified to earnings in the next 12 months. Actual amounts reclassified to earnings depend on the foreign exchange rates, interest rates and commodity prices in effect when derivative contracts that are currently outstanding mature. For all forecasted transactions, the maximum term over which we are hedging exposures to the variability of cash flows is two years as at December 31, 2024.

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

Year ended December 31,	**2024**	2023	2022
(millions of Canadian dollars)			
Foreign exchange contracts[1]	**(2,033)**	1,292	(1,344)
Interest rate contracts[2]	**112**	(63)	10
Commodity contracts[3]	**(163)**	(41)	50
Other contracts[4]	**2**	(8)	4
Total unrealized derivative fair value gain/(loss), net	**(2,082)**	1,180	(1,280)

1 For the respective years ended, reported within Transportation and other services revenues (2024 - nil ; 2023 - $645 million gain; 2022 - $238 million loss) and Other income/(expense) (2024 - $2,033 million loss; 2023 - $647 million gain; 2022 - $1,106 million loss) in the Consolidated Statements of Earnings.
2 Reported within Interest expense in the Consolidated Statements of Earnings.
3 For the respective years ended, reported within Transportation and other services revenues (2024 - $23 million loss; 2023 - $35 million loss; 2022 - $13 million gain), Commodity sales (2024 - $92 million loss; 2023 - $153 million gain; 2022 - $89 million gain), Commodity costs (2024 - $31 million loss; 2023 - $94 million loss; 2022 - $102 million loss) and Operating and administrative expense (2024 - $17 million loss; 2023 - $65 million loss; 2022 - $50 million gain) in the Consolidated Statements of Earnings.
4 Reported within Operating and administrative expense in the Consolidated Statements of Earnings.

LIQUIDITY RISK

Liquidity risk is the risk that we will not be able to meet our financial obligations, including commitments and guarantees, as they become due. In order to mitigate this risk, we forecast cash requirements over a 12-month rolling time period to determine whether sufficient funds will be available. Our primary sources of liquidity and capital resources are funds generated from operations, the issuance of commercial paper and draws under committed credit facilities and long-term debt, which includes debentures and medium-term notes. Our shelf prospectuses with securities regulators enable ready access to either the Canadian or US public capital markets, subject to market conditions. In addition, we maintain sufficient liquidity through committed credit facilities with a diversified group of banks and institutions which, if necessary, enables us to fund all anticipated requirements for approximately one year without accessing the capital markets. We were in compliance with all the terms and conditions of our committed credit facility agreements and term debt indentures as at December 31, 2024. As a result, all credit facilities are available to us and the banks are obligated to fund us under the terms of the facilities. We also identify other potential sources of debt and equity funding alternatives, including reinstatement of our dividend reinvestment and share purchase plan or at-the-market equity issuances.

CREDIT RISK

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

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

December 31,	**2024**	2023
(millions of Canadian dollars)		
Canadian financial institutions	**344**	457
US financial institutions	**128**	252
European financial institutions	**116**	107
Asian financial institutions	**53**	121
Other[1]	**332**	125
	973	1,062

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

As at December 31, 2024, we did not provide any letters of credit in lieu of providing cash collateral to our counterparties pursuant to the terms of the relevant ISDA agreements. We held no cash collateral on derivative asset exposures as at December 31, 2024 and 2023.

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

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

FAIR VALUE MEASUREMENTS

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

FAIR VALUE OF FINANCIAL INSTRUMENTS

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

Level 1

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

Level 2

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

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

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

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

Fair Value of Derivatives

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

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

December 31, 2023	Level 1	Level 2	Level 3	Total Gross Derivative Instruments
(millions of Canadian dollars)				
Financial assets				
Current derivative assets				
Foreign exchange contracts	—	139	—	139
Interest rate contracts	—	65	—	65
Commodity contracts	142	103	173	418
Other contracts	—	1	—	1
	142	308	173	623
Long-term derivative assets				
Foreign exchange contracts	—	335	—	335
Interest rate contracts	—	53	—	53
Commodity contracts	—	24	51	75
	—	412	51	463
Financial liabilities				
Current derivative liabilities				
Foreign exchange contracts	—	(128)	—	(128)
Interest rate contracts	—	(186)	—	(186)
Commodity contracts	(136)	(76)	(211)	(423)
Other contracts	—	(1)	—	(1)
	(136)	(391)	(211)	(738)
Long-term derivative liabilities				
Foreign exchange contracts	—	(498)	—	(498)
Interest rate contracts	—	(88)	—	(88)
Commodity contracts	—	(22)	(144)	(166)
	—	(608)	(144)	(752)
Total net derivative asset/(liability)				
Foreign exchange contracts	—	(152)	—	(152)
Interest rate contracts	—	(156)	—	(156)
Commodity contracts	6	29	(131)	(96)
Other contracts	—	—	—	—
	6	(279)	(131)	(404)

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

December 31, 2024	Fair Value	Unobservable Input	Minimum Price/ Volatility	Maximum Price/ Volatility	Weighted Average Price/Volatility	Unit of Measurement
(fair value in millions of Canadian dollars)						
Commodity contracts - financial[1]						
Natural gas	**(5)**	**Forward gas price**	**3.73**	**9.85**	**4.12**	**$/mmbtu[2]**
Crude	**(13)**	**Forward crude price**	**73.54**	**104.42**	**97.44**	**$/barrel**
Power	**(44)**	**Forward power price**	**31.17**	**229.29**	**68.51**	**$/MW/H**
Commodity contracts - physical[1]						
Natural gas	**(80)**	**Forward gas price**	**1.40**	**22.57**	**4.12**	**$/mmbtu[2]**
Crude	**22**	**Forward crude price**	**77.31**	**118.28**	**99.76**	**$/barrel**
Power	**(98)**	**Forward power price**	**12.94**	**211.42**	**70.30**	**$/MW/H**
Commodity options[3]						
Natural gas	**166**	**Forward gas price**	**2.44**	**7.09**	**4.44**	**$/mmbtu[2]**
		Price volatility	**3%**	**77%**	**50%**	
	(52)					

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

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

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

Year ended December 31,	**2024**	2023
(millions of Canadian dollars)		
Level 3 net derivative liability at beginning of year	**(131)**	(136)
Total gain/(loss), unrealized		
Included in earnings[1]	**(92)**	(48)
Included in OCI	**19**	67
Included in regulatory assets/liabilities	**130**	—
Settlements	**22**	(14)
Level 3 net derivative liability at end of year	**(52)**	(131)

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

There were no transfers into or out of Level 3 as at December 31, 2024 or 2023.

Net Investment Hedges

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

During the years ended December 31, 2024 and 2023, we recognized unrealized foreign exchange losses of $1,185 million and gains of $645 million, respectively, on the translation of US dollar-denominated debt, in OCI. No unrealized gains or losses on the change in fair value of our outstanding foreign exchange forward contracts were recognized in OCI during the years ended December 31, 2024 and 2023. No realized gains or losses associated with the settlement of foreign exchange forward contracts were recognized in OCI during the years ended December 31, 2024 and 2023. During the years ended December 31, 2024 and 2023, we recognized realized losses of $120 million and losses of $236 million, respectively, associated with the settlement of US dollar-denominated debt that had matured during the period, in OCI.

Fair Value of Other Financial Instruments
Certain long-term investments in other entities with no actively quoted prices are classified as FVMA investments and are recorded at cost less impairment. The carrying value of FVMA investments totaled $187 million and $173 million as at December 31, 2024 and 2023, respectively.

We have wholly-owned captive insurance subsidiaries whose principal activity is providing insurance and reinsurance coverage for certain insurable property and casualty risk exposures of our operating subsidiaries and certain equity investments. As at December 31, 2024, the fair value of investments in equity funds and debt securities held by our captive insurance subsidiaries was $114 million and $1.1 billion, respectively (2023 - $287 million and $284 million, respectively). Our investments in debt securities had a cost basis of $1.1 billion as at December 31, 2024 (2023 - $279 million). These investments in equity funds and debt securities are recognized at fair value, classified as Level 1 and Level 2 in the fair value hierarchy, respectively, and are recorded in Other current assets and Long-term investments in the Consolidated Statements of Financial Position. There were unrealized holding losses of $16 million for the year ended December 31, 2024 (2023 - gains of $34 million).

As at December 31, 2024 and 2023, our long-term debt had a carrying value of $101.6 billion and $81.2 billion, respectively, before debt issuance costs and a fair value of $98.9 billion and $78.1 billion, respectively.

As at December 31, 2024 and 2023, we had investments with a fair value of $998 million and $717 million, respectively, included in Restricted long-term investments and cash in the Consolidated Statements of Financial Position which are classified as available-for-sale. These securities represent restricted funds held in trust for the purpose of funding pipeline abandonment in accordance with the CER's regulatory requirements, to cover future pipeline decommissioning costs in the state of Minnesota and to satisfy retirement obligations as Wexpro properties are abandoned.

We had restricted long-term investments and cash held in trust totaling $491 million and $263 million as at December 31, 2024 and 2023, respectively, which are classified as Level 1 in the fair value hierarchy. We also had restricted long-term investments held in trust totaling $507 million (cost basis - $540 million) and $454 million (cost basis - $486 million) as at December 31, 2024 and 2023, respectively, which are classified as Level 2 in the fair value hierarchy. There were unrealized holding gains of $33 million and $51 million on these investments for the years ended December 31, 2024 and 2023, respectively. Within Other long-term liabilities we had estimated future abandonment costs related to LMCI of $826 million and $745 million as at December 31, 2024 and 2023, respectively *(Note 7)*.

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

24. INCOME TAXES

INCOME TAX RATE RECONCILIATION

Year ended December 31,	**2024**	2023	2022
(millions of Canadian dollars)			
Earnings before income taxes	**7,299**	7,879	4,542
Canadian federal statutory income tax rate	**15%**	15%	15%
Expected federal taxes at statutory rate	**1,095**	1,182	681
Increase/(decrease) resulting from:			
Provincial and state income taxes[1]	**183**	411	108
Foreign and other statutory rate differentials[2]	**340**	187	295
Effects of rate-regulated accounting[3,4]	**(192)**	(106)	(122)
Write-off of regulatory deferrals[3,5]	**4**	115	—
Part VI.1 tax, net of federal Part I deduction[3,6]	**73**	66	76
US Minimum Tax	**148**	100	107
Non-taxable portion of gain on sale of investment[3,7]	**(147)**	—	—
Valuation allowance[3]	**(2)**	(12)	6
Accounting impairment of non-deductible goodwill[3,8]	**148**	—	370
Noncontrolling interests[3,9]	**(30)**	19	9
Investment and production tax credits	**(23)**	(47)	—
Other[3]	**71**	(94)	74
Income tax expense	**1,668**	1,821	1,604
Effective income tax rate	**22.9%**	23.1%	35.3%

1 *The change in provincial and state income taxes from 2023 to 2024 reflects the decrease in earnings from Canadian operations partially offset by an increase in earnings from US operations before considering the non-deductible goodwill impairment to the Gas Transmission segment. Refer to* Note 13 - Long-Term Investments*.*

2 *The change in foreign and other statutory rate differentials from 2023 to 2024 reflects the increase in earnings from US operations before considering the non-deductible goodwill impairment to the Gas Transmission segment. Refer to* Note 13 - Long-Term Investments.

3 *The provincial and state tax component of these items is included in the Provincial and state income taxes above.*

4 *The amount in 2024 includes the effects of rate regulated accounting attributable to the Acquisitions. Refer to* Note 8 - Acquisitions and Disposition.

5 *The amount in 2023 includes the federal tax impact of the de-recognition of rate-regulated accounting for income tax relating to Southern Lights Canada and portions of the Canadian Mainline including Line 9 and L3R. Refer to* Note 7 - Regulatory Matters*.*

6 *Part VI.1 tax is a tax levied on preferred share dividends paid in Canada.*

7 *The amount in 2024 represents the federal component of the non-taxable portion of the gain on sales relating to Alliance Pipeline and Aux Sable. Refer to* Note 13 - Long-Term Investments*.*

8 *The amounts relates to the federal impact of the non-deductible goodwill impairment to the Gas Transmissions segment. Refer to* Note 13 - Long-Term Investments *and* Note 15 - Goodwill.

9 *The amount in 2023 and 2022 includes the federal tax impact of impairments to Chapman Ranch and Magic Valley attributable to non-controlling interests in those respective years. Refer to* Note 11 - Property, Plant and Equipment.

COMPONENTS OF PRETAX EARNINGS AND INCOME TAXES

Year ended December 31,	**2024**	2023	2022
(millions of Canadian dollars)			
Earnings before income taxes			
Canada	**1,035**	2,233	583
US	**5,231**	4,620	2,865
Other	**1,033**	1,026	1,094
	7,299	7,879	4,542
Current income taxes			
Canada	**248**	100	360
US	**578**	191	201
Other	**123**	110	86
	949	401	647
Deferred income taxes			
Canada	**(299)**	456	(358)
US	**1,013**	974	1,309
Other	**5**	(10)	6
	719	1,420	957
Income tax expense	**1,668**	1,821	1,604

COMPONENTS OF DEFERRED INCOME TAXES

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

December 31,	**2024**	2023
(millions of Canadian dollars)		
Deferred income tax liabilities		
Property, plant and equipment	**(11,368)**	(9,202)
Investments	**(9,043)**	(7,765)
Regulatory assets	**(1,940)**	(1,338)
Other	**(251)**	(52)
Total deferred income tax liabilities	**(22,602)**	(18,357)
Deferred income tax assets		
Financial instruments	**740**	271
Loss carryforwards	**1,272**	1,745
Other	**2,088**	1,798
Total deferred income tax assets	**4,100**	3,814
Less valuation allowance	**(298)**	(147)
Total deferred income tax assets, net	**3,802**	3,667
Net deferred income tax liabilities, net	**(18,800)**	(14,690)
Presented as follows:		
Total deferred income tax assets	**796**	341
Total deferred income tax liabilities	**(19,596)**	(15,031)
Net deferred income tax liabilities, net	**(18,800)**	(14,690)

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

As at both December 31, 2024 and 2023, we recognized the benefit of unused tax loss carryforwards of $1.3 billion in Canada which expire in 2031 and beyond.

As at December 31, 2024, and 2023, we recognized the benefit of unused tax loss carryforwards of $4.2 billion and $6.4 billion, respectively, in the US with no expiration.

We have not provided for deferred income taxes on the difference between the carrying value of substantially all of our foreign subsidiaries and their corresponding tax basis as the earnings of those subsidiaries are intended to be permanently reinvested in their operations. As such, these investments are not anticipated to give rise to income taxes in the foreseeable future. The difference between the carrying values of the investments and their tax bases is largely a result of unremitted earnings and currency translation adjustments. The unremitted earnings and currency translation adjustment for which no deferred taxes have been recognized in respect of foreign subsidiaries were $9.5 billion and $6.6 billion for the periods ended December 31, 2024 and 2023, respectively. If such earnings are remitted, in the form of dividends or otherwise, we may be subject to income taxes and foreign withholding taxes. The determination of the amount of unrecognized deferred income tax liabilities applicable to such amounts is not practicable.

Enbridge and certain of our subsidiaries are subject to taxation in Canada, the US and other foreign jurisdictions. The material jurisdictions in which we are subject to potential examinations include the US (Federal) and Canada (Federal, Alberta and Québec). We are open to examination by Canadian tax authorities for the 2017 to 2024 tax years and by US tax authorities for the 2021 to 2024 tax years. We are currently under examination for income tax matters in Canada for the 2018 to 2021 tax years. We are not currently under examination for income tax matters in any other material jurisdiction where we are subject to income tax.

UNRECOGNIZED TAX BENEFITS

Year ended December 31,	**2024**	2023
(millions of Canadian dollars)		
Unrecognized tax benefits at beginning of year	**45**	55
Gross decreases for tax positions of prior year	**(2)**	(2)
Change in translation of foreign currency	**4**	(1)
Lapses of statute of limitations	**(16)**	(7)
Unrecognized tax benefits at end of year	**31**	45

The unrecognized tax benefits as at December 31, 2024, if recognized, would impact our effective income tax rate. We do not anticipate further adjustments to the unrecognized tax benefits during the next 12 months that would have a material impact on our consolidated financial statements.

We recognize accrued interest and penalties related to unrecognized tax benefits as a component of income taxes. Interest and penalties included in income taxes for the years ended December 31, 2024 and 2023 were $8 million recovery and $1 million expense, respectively. As at December 31, 2024 and 2023, interest and penalties of $6 million and $14 million, respectively, have been accrued.

25. PENSION AND OTHER POSTRETIREMENT BENEFITS

PENSION PLANS

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

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

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

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

	Canada		US	
December 31,	**2024**	2023	**2024**	2023
(millions of Canadian dollars)				
Change in projected benefit obligation				
Projected benefit obligation at beginning of year	**4,092**	3,630	**1,036**	1,029
Service cost	**103**	81	**60**	40
Interest cost	**186**	184	**69**	47
Participant contributions	**32**	31	**—**	—
Actuarial (gain)/loss[1]	**—**	359	**(98)**	31
Benefits paid	**(210)**	(193)	**(100)**	(76)
Transfer in	**—**	—	**569**	—
Foreign currency exchange rate changes	**—**	—	**119**	(29)
Other	**—**	—	**(7)**	(6)
Projected benefit obligation at end of year[2]	**4,203**	4,092	**1,648**	1,036
Change in plan assets				
Fair value of plan assets at beginning of year	**4,528**	4,234	**1,052**	1,080
Actual return on plan assets	**627**	427	**197**	78
Employer contributions	**23**	27	**5**	5
Participant contributions	**32**	31	**—**	—
Benefits paid	**(210)**	(193)	**(100)**	(76)
Transfer in	**—**	—	**900**	—
Foreign currency exchange rate changes	**—**	—	**146**	(29)
Other	**—**	2	**(6)**	(6)
Fair value of plan assets at end of year[3]	**5,000**	4,528	**2,194**	1,052
Overfunded status at end of year	**797**	436	**546**	16
Presented as follows:				
Deferred amounts and other assets	**943**	636	**653**	116
Other current liabilities	**(10)**	(8)	**(6)**	(5)
Other long-term liabilities	**(136)**	(192)	**(101)**	(95)
	797	436	**546**	16

1 Primarily due to the increase in the discount rate and changes in benefit assumptions and member data used to measure the defined benefit obligations (2023 - primarily due to the decrease in the discount rates used to measure the benefit obligation).

2 The accumulated benefit obligation for our Canadian pension plans was $3.9 billion and $3.8 billion as at December 31, 2024 and 2023, respectively. The accumulated benefit obligation for our US pension plans was $1.6 billion and $1.0 billion as at December 31, 2024 and 2023, respectively.

3 Assets in the amount of $18 million (2023 - $14 million) and $80 million (2023 - $62 million), related to our Canadian and US non-registered supplemental pension plan obligations, respectively, are held in grantor trusts and rabbi trusts that, in accordance with federal tax regulations, are not restricted from creditors. These assets are committed for the future settlement of benefit obligations included in the underfunded status as at the end of the year, however they are excluded from plan assets for accounting purposes.

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

	Canada		US	
December 31,	**2024**	2023	**2024**	2023
(millions of Canadian dollars)				
Accumulated benefit obligation	**404**	394	**107**	99
Fair value of plan assets	**283**	243	**—**	—

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

	Canada		US	
December 31,	**2024**	2023	**2024**	2023
(millions of Canadian dollars)				
Projected benefit obligation	**428**	416	**107**	99
Fair value of plan assets	**283**	243	**—**	—

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

	Canada		US	
December 31,	**2024**	2023	**2024**	2023
(millions of Canadian dollars)				
Net actuarial (gain)/loss	**(122)**	51	**(42)**	74
Prior service cost	**—**	—	**5**	1
Total amount recognized in AOCI[1]	**(122)**	51	**(37)**	75

1 Excludes amounts related to CTA.

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

	Canada			US		
Year ended December 31,	**2024**	2023	2022	**2024**	2023	2022
(millions of Canadian dollars)						
Service cost[1]	**103**	81	131	**60**	40	43
Interest cost[2]	**186**	184	127	**69**	47	24
Expected return on plan assets[2]	**(304)**	(271)	(295)	**(131)**	(77)	(85)
Amortization/settlement of net actuarial (gain)/loss[2]	**4**	—	8	**7**	(4)	—
Amortization/curtailment of prior service credit[2]	**—**	—	—	**(4)**	—	(2)
Net periodic benefit (credit)/cost	**(11)**	(6)	(29)	**1**	6	(20)
Defined contribution benefit cost	**12**	12	10	**—**	—	—
Net pension (credit)/cost recognized in Earnings	**1**	6	(19)	**1**	6	(20)
Amount recognized in OCI:						
Amortization/settlement of net actuarial (gain)/loss	**—**	—	(2)	**—**	4	—
Amortization/curtailment of prior service credit	**—**	—	—	**4**	—	2
Net actuarial (gain)/loss arising during the year	**(173)**	115	(288)	**(116)**	30	(52)
Total amount recognized in OCI	**(173)**	115	(290)	**(112)**	34	(50)
Total amount recognized in Comprehensive income	**(172)**	121	(309)	**(111)**	40	(70)

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

Actuarial Assumptions

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

	Canada			US		
	2024	2023	2022	**2024**	2023	2022
Projected benefit obligation						
Discount rate	**4.7%**	4.6%	5.1%	**5.5%**	4.7%	4.9%
Rate of salary increase	**3.0%**	3.0%	2.9%	**2.6%**	2.6%	2.8%
Cash balance interest credit rate	**N/A**	N/A	N/A	**4.0%**	4.5%	4.3%
Net periodic benefit cost						
Discount rate	**4.6%**	5.3%	3.2%	**4.8%**	4.9%	2.6%
Rate of return on plan assets	**6.8%**	6.5%	6.6%	**7.3%**	7.4%	7.4%
Rate of salary increase	**3.0%**	2.9%	2.9%	**2.8%**	2.8%	2.8%
Cash balance interest credit rate	**N/A**	N/A	N/A	**4.4%**	4.3%	4.3%

OTHER POSTRETIREMENT BENEFIT PLANS

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

Benefit Obligations, Plan Assets and Funded Status

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

	Canada		US	
December 31,	**2024**	2023	**2024**	2023
(millions of Canadian dollars)				
Change in accumulated postretirement benefit obligation				
Accumulated postretirement benefit obligation at beginning of year	**228**	211	**129**	136
Service cost	**3**	3	**3**	1
Interest cost	**10**	11	**7**	6
Participant contributions	**—**	—	**5**	5
Actuarial (gain)/loss[1]	**(21)**	13	**(9)**	4
Benefits paid	**(10)**	(10)	**(20)**	(20)
Transfer in	**—**	—	**46**	—
Foreign currency exchange rate changes	**—**	—	**16**	(3)
Accumulated postretirement benefit obligation at end of year	**210**	228	**177**	129
Change in plan assets				
Fair value of plan assets at beginning of year	**—**	—	**187**	185
Actual return on plan assets	**—**	—	**22**	14
Employer contributions	**10**	10	**7**	7
Participant contributions	**—**	—	**5**	5
Benefits paid	**(10)**	(10)	**(20)**	(20)
Transfer in	**—**	—	**55**	—
Foreign currency exchange rate changes	**—**	—	**20**	(4)
Other	**—**	—	**2**	—
Fair value of plan assets at end of year	**—**	—	**278**	187
Overfunded/(underfunded) status at end of year	**(210)**	(228)	**101**	58
Presented as follows:				
Deferred amounts and other assets	**—**	—	**113**	73
Other current liabilities	**(11)**	(12)	**—**	—
Other long-term liabilities	**(199)**	(216)	**(12)**	(15)
	(210)	(228)	**101**	58

1 Primarily due to the increase in the discount rate and changes in benefit assumptions and member data used to measure the defined benefit obligation (2023 - primarily due to decrease in the discount rate used to measure the benefit obligations).

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

	Canada		US	
December 31,	**2024**	2023	**2024**	2023
(millions of Canadian dollars)				
Accumulated benefit obligation	**210**	228	**100**	78
Fair value of plan assets	**—**	—	**88**	63

Amount Recognized in Accumulated Other Comprehensive Income

The amount of pre-tax AOCI relating to our OPEB plans are as follows:

	Canada		US	
December 31,	**2024**	2023	**2024**	2023
(millions of Canadian dollars)				
Net actuarial gain	**(99)**	(82)	**(103)**	(96)
Prior service credit	**—**	(1)	**(16)**	(22)
Total amount recognized in AOCI[1]	**(99)**	(83)	**(119)**	(118)

1 Excludes amounts related to CTA.

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

	Canada			US		
Year ended December 31,	**2024**	2023	2022	**2024**	2023	2022
(millions of Canadian dollars)						
Service cost[1]	**3**	3	4	**3**	1	1
Interest cost[2]	**10**	11	7	**7**	6	3
Expected return on plan assets[2]	**—**	—	—	**(15)**	(11)	(12)
Amortization/settlement of net actuarial gain[2]	**(5)**	(6)	(1)	**(5)**	(6)	(6)
Amortization/curtailment of prior service credit[2]	**(1)**	—	—	**(6)**	(8)	(7)
Net periodic benefit (credit)/cost recognized in Earnings	**7**	8	10	**(16)**	(18)	(21)
Amount recognized in OCI:						
Amortization/settlement of net actuarial gain	**5**	6	1	**5**	6	6
Amortization/curtailment of prior service credit	**1**	—	—	**6**	8	7
Net actuarial (gain)/loss arising during the year	**(22)**	13	(67)	**(12)**	—	(4)
Total amount recognized in OCI	**(16)**	19	(66)	**(1)**	14	9
Total amount recognized in Comprehensive income	**(9)**	27	(56)	**(17)**	(4)	(12)

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

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

	Canada			US		
	2024	2023	2022	**2024**	2023	2022
Accumulated postretirement benefit obligation						
Discount rate	**4.7%**	4.6%	5.3%	**5.3%**	4.7%	4.9%
Net periodic benefit cost						
Discount rate	**4.6%**	5.3%	3.2%	**5.5%**	4.9%	2.4%
Rate of return on plan assets	**N/A**	N/A	N/A	**6.7%**	5.9%	6.0%

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

	Canada		US[1]	
	2024	2023	**2024**	2023
Health care cost trend rate assumed for next year	**4.0%**	4.0%	**3.2%**	4.7%
Rate to which the cost trend is assumed to decline (ultimate trend rate)	**4.0%**	4.0%	**3.7%**	3.3%
Year that the rate reaches the ultimate trend rate	**N/A**	N/A	**2023 - 2046**	2022 - 2045

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

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

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

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

	Canada			US		
	Target	December 31,		Target	December 31,	
Asset Category	**Allocation**	**2024**	2023	**Allocation**	**2024**	2023
Equity securities	**46.2%**	**39.1%**	41.4%	**43.4%**	**44.8%**	39.5%
Fixed income securities	**23.0%**	**31.6%**	29.6%	**23.2%**	**33.0%**	19.4%
Alternatives[1]	**30.8%**	**29.3%**	29.0%	**33.4%**	**22.2%**	41.1%

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

Pension Plans

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

	Canada				US			
	Level 1[1]	Level 2[2]	Level 3[3]	Total	Level 1[1]	Level 2[2]	Level 3[3]	Total
(millions of Canadian dollars)								
December 31, 2024								
Cash and cash equivalents	**201**	**—**	**—**	**201**	**57**	**—**	**—**	**57**
Equity securities[4]								
Canada	**—**	**3**	**—**	**3**	**—**	**—**	**—**	**—**
Global	**134**	**1,817**	**—**	**1,951**	**27**	**954**	**—**	**981**
Fixed income securities[4]								
Government	**—**	**543**	**—**	**543**	**—**	**194**	**—**	**194**
Corporate	**—**	**838**	**—**	**838**	**—**	**474**	**—**	**474**
Alternatives[5]	**—**	**—**	**1,464**	**1,464**	**—**	**—**	**488**	**488**
Total pension plan assets at fair value	**335**	**3,201**	**1,464**	**5,000**	**84**	**1,622**	**488**	**2,194**
December 31, 2023								
Cash and cash equivalents	227	—	—	227	8	—	—	8
Equity securities[4]								
Canada	—	3	—	3	—	—	—	—
Global	—	1,871	—	1,871	—	416	—	416
Fixed income securities[4]								
Government	—	446	—	446	—	46	—	46
Corporate	—	667	—	667	—	149	—	149
Alternatives[5]	—	—	1,290	1,290	—	—	433	433
Forward currency contracts	—	24	—	24	—	—	—	—
Total pension plan assets at fair value	227	3,011	1,290	4,528	8	611	433	1,052

1 Level 1 assets include assets with quoted prices in active markets for identical assets.
2 Level 2 assets include assets with significant observable inputs.
3 Level 3 assets include assets with significant unobservable inputs.
4 Pension plan assets include $77 million (2023 - $61 million) of indirectly held related party equity and fixed income securities investments.
5 Alternatives include investments in private debt, private equity, infrastructure and real estate funds.

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

	Canada		US	
December 31,	**2024**	2023	**2024**	2023
(millions of Canadian dollars)				
Balance at beginning of year	**1,290**	1,291	**433**	445
Unrealized and realized gains/(losses)	**104**	(41)	**63**	(12)
Purchases and settlements, net	**70**	40	**(8)**	—
Balance at end of year	**1,464**	1,290	**488**	433

OPEB Plans

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

	Level 1[1]	Level 2[2]	Level 3[3]	Total
(millions of Canadian dollars)				
December 31, 2024				
Cash and cash equivalents	**4**	**—**	**—**	**4**
Equity securities				
US	**—**	**52**	**—**	**52**
Global	**—**	**93**	**—**	**93**
Fixed income securities				
Government	**71**	**6**	**—**	**77**
Corporate	**—**	**19**	**—**	**19**
Alternatives[4]	**—**	**—**	**33**	**33**
Total OPEB plan assets at fair value	**75**	**170**	**33**	**278**
December 31, 2023				
Cash and cash equivalents	3	—	—	3
Equity securities				
US	—	36	—	36
Global	—	62	—	62
Fixed income securities				
Government	42	3	—	45
Corporate	—	12	—	12
Alternatives[4]	—	—	29	29
Total OPEB plan assets at fair value	45	113	29	187

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

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

December 31,	**2024**	2023
(millions of Canadian dollars)		
Balance at beginning of year	**29**	28
Unrealized and realized gains	**5**	1
Purchases and settlements, net	**(1)**	—
Balance at end of year	**33**	29

EXPECTED BENEFIT PAYMENTS

Year ending December 31,	2025	2026	2027	2028	2029	2030-2034
(millions of Canadian dollars)						
Pension						
Canada	214	220	226	232	238	1,285
US	117	120	123	123	120	625
OPEB						
Canada	11	12	12	12	12	64
US	16	16	16	16	16	71

EXPECTED EMPLOYER CONTRIBUTIONS

In 2025, we expect to contribute approximately $21 million and $6 million to the Canadian and US pension plans, respectively, and $11 million and $6 million to the Canadian and US OPEB plans, respectively.

RETIREMENT SAVINGS PLANS

In addition to the pension and OPEB plans discussed above, we also have defined contribution employee savings plans available to US employees. Employees may receive a matching contribution where we match a certain percentage of before-tax employee contributions ranging from 3.0% to 7.0% of eligible pay per pay period. For the year ended December 31, 2024, pre-tax employer matching contribution costs were $35 million ($33 million in 2023 and $30 million in 2022).

26. LEASES

LESSEE

We incur operating lease expenses related primarily to real estate, pipelines, storage and equipment. Our operating leases have remaining lease terms of 2 months to 41 years as at December 31, 2024.

For the years ended December 31, 2024, 2023 and 2022, we incurred operating lease expenses of $132 million, $131 million and $118 million, respectively. Operating lease expenses are reported under Operating and administrative expense in the Consolidated Statements of Earnings.

For the years ended December 31, 2024, 2023 and 2022, operating lease payments to settle lease liabilities were $128 million, $129 million and $123 million, respectively. Operating lease payments are reported under Operating activities in the Consolidated Statements of Cash Flows.

Supplemental Statements of Financial Position Information

(millions of Canadian dollars, except lease term and discount rate)	**December 31, 2024**	December 31, 2023
Operating leases[1]		
Operating lease right-of-use assets, net[2]	**785**	669
Operating lease liabilities - current[3]	**121**	98
Operating lease liabilities - long-term[3]	**738**	652
Total operating lease liabilities	**859**	750
Finance leases		
Finance lease right-of-use assets, net[4]	**294**	287
Finance lease liabilities - current[5]	**16**	19
Finance lease liabilities - long-term[5]	**300**	264
Total finance lease liabilities	**316**	283
Weighted average remaining lease term		
Operating leases	**14 years**	12 years
Finance leases	**31 years**	31 years
Weighted average discount rate		
Operating leases	**4.8%**	4.5%
Finance leases	**5.8%**	5.7%

1 Affiliate ROU assets, current lease liabilities and long-term lease liabilities as at December 31, 2024 were $42 million (December 31, 2023 - $42 million), $6 million (December 31, 2023 - $5 million) and $37 million (December 31, 2023 - $38 million), respectively.

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

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

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

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

As at December 31, 2024, our operating and finance lease liabilities are expected to mature as follows:

(millions of Canadian dollars)	Operating leases	Finance leases
2025	**148**	**31**
2026	**134**	**30**
2027	**123**	**23**
2028	**97**	**23**
2029	**65**	**22**
Thereafter	**685**	**531**
Total undiscounted lease payments	**1,252**	**660**
Less imputed interest	**(393)**	**(344)**
Total	**859**	**316**

LESSOR

We receive revenues from operating leases primarily related to natural gas and crude oil storage and processing facilities, and wind power generation assets. Our operating leases have remaining lease terms of 3 months to 27 years as at December 31, 2024.

Year ended December 31,	**2024**	2023	2022
(millions of Canadian dollars)			
Operating lease income	**229**	241	266
Variable lease income	**321**	299	321
Total lease income[1]	**550**	540	587

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

As at December 31, 2024, our future lease payments to be received under operating lease contracts where we are the lessor are as follows:

	Operating leases
(millions of Canadian dollars)	
2025	**221**
2026	**202**
2027	**197**
2028	**198**
2029	**199**
Thereafter	**1,415**
Future lease payments	**2,432**

27. OTHER INCOME/(EXPENSE)

Year ended December 31,	**2024**	2023	2022
(millions of Canadian dollars)			
Realized foreign currency gain/(loss)	**121**	(129)	92
Unrealized foreign currency gain/(loss)	**(2,199)**	821	(1,094)
Net defined pension and OPEB credit	**188**	135	239
Other	**564**	397	174
	(1,326)	1,224	(589)

28. CHANGES IN OPERATING ASSETS AND LIABILITIES

Year ended December 31,	**2024**	2023	2022
(millions of Canadian dollars)			
Trade receivables and unbilled revenues	**(1,638)**	1,125	(572)
Accounts receivable from affiliates	**(23)**	18	17
Inventory	**177**	763	(599)
Other current and non-current assets	**(426)**	1,301	(394)
Trade payables and accrued liabilities	**1,383**	(1,542)	585
Accounts payable to affiliates	**(8)**	(66)	16
Interest payable	**157**	199	58
Other current and long-term liabilities	**245**	513	877
	(133)	2,311	(12)

29. RELATED PARTY TRANSACTIONS

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

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

Our transactions with significantly influenced investees are as follows:

Year ended December 31,	**2024**	2023	2022
(millions of Canadian dollars)			
Transportation and other revenues	**181**	169	185
Commodity sales	**—**	—	51
Operating and administrative[1]	**637**	625	503
Commodity costs[2]	**22**	63	778
Gas distribution costs	**147**	140	136

1 During the years ended December 31, 2024, 2023 and 2022, we had Operating and administrative costs from the Seaway Crude Pipeline System of $650 million, $632 million and $495 million, respectively. These costs are a result of an operational contract where we utilize capacity on Seaway Crude Pipeline System assets for use in our Liquids Pipelines business.

2 During the years ended December 31, 2024, 2023 and 2022, we had Commodity costs from Aux Sable Canada LP of nil, $2 million and $571 million, respectively.

30. COMMITMENTS AND CONTINGENCIES

COMMITMENTS

As at December 31, 2024, we have commitments as detailed below:

	Total	Less than 1 year	2 years	3 years	4 years	5 years	Thereafter
(millions of Canadian dollars)							
Purchase of services, pipe and other materials, including transportation[1]	14,019	4,260	2,047	1,755	1,535	1,200	3,222
Maintenance agreements[2]	452	57	56	57	36	36	210
Right-of-ways commitments[3]	981	52	48	53	49	49	730
Total	15,452	4,369	2,151	1,865	1,620	1,285	4,162

1 Includes capital and operating commitments. Consists primarily of firm capacity payments that provide us with uninterrupted firm access to natural gas and crude oil transportation and storage contracts; contractual obligations to purchase physical quantities of natural gas; and power commitments.

2 Consists primarily of maintenance service contracts for our wind and solar assets.

3 Our right-of-way obligations primarily consist of non-lease agreements that existed at the time of adopting Topic 842 Leases, at which time we elected a practical expedient that allowed us to continue our historical treatment.

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

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

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

TAX MATTERS
We and our subsidiaries maintain tax liabilities related to uncertain tax positions. While fully supportable in our view, these tax positions, if challenged by tax authorities, may not be fully sustained on review.

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

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

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

31. GUARANTEES

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

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

The likelihood of having to perform under these guarantees and indemnifications is largely dependent upon future operations of various subsidiaries, investees and other third parties, or the occurrence of certain future events. We cannot reasonably estimate the total maximum potential amounts that could become payable to third parties and affiliates under such agreements described above; however, historically, we have not made any significant payments under guarantee or indemnification provisions. While these agreements may specify a maximum potential exposure, or a specified duration to the guarantee or indemnification obligation, there are circumstances where the amount and duration are unlimited. As at December 31, 2024, guarantees and indemnifications have not had, and are not reasonably likely to have, a material effect on our financial condition, changes in financial condition, earnings, liquidity, capital expenditures or capital resources.

32. QUARTERLY FINANCIAL DATA (UNAUDITED)

	Q1	Q2	Q3	Q4	Total
(unaudited; millions of Canadian dollars, except per share amounts)					
2024					
Operating revenues	**11,038**	**11,336**	**14,882**	**16,217**	**53,473**
Operating income	**2,711**	**2,273**	**2,218**	**2,447**	**9,649**
Earnings	**1,565**	**2,001**	**1,447**	**618**	**5,631**
Earnings attributable to controlling interests	**1,512**	**1,943**	**1,391**	**595**	**5,441**
Earnings attributable to common shareholders	**1,419**	**1,848**	**1,293**	**493**	**5,053**
Earnings per common share					
Basic	**0.67**	**0.86**	**0.59**	**0.23**	**2.34**
Diluted	**0.67**	**0.86**	**0.59**	**0.23**	**2.34**
2023					
Operating revenues	12,075	10,432	9,844	11,298	43,649
Operating income	2,662	2,350	1,794	1,845	8,651
Earnings	1,866	2,001	623	1,568	6,058
Earnings attributable to controlling interests	1,817	1,935	621	1,818	6,191
Earnings attributable to common shareholders	1,733	1,848	532	1,726	5,839
Earnings per common share					
Basic	0.86	0.91	0.26	0.81	2.84
Diluted	0.85	0.91	0.26	0.81	2.84

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

DISCLOSURE CONTROLS AND PROCEDURES

Disclosure controls and procedures are designed to provide reasonable assurance that information required to be disclosed in reports filed with, or submitted to, securities regulatory authorities is recorded, processed, summarized and reported within the time periods specified under Canadian and US securities law. As at December 31, 2024, an evaluation was carried out under the supervision of and with the participation of our management, including the Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operations of our disclosure controls and procedures (as defined in Rule 13a-15(e) and 15d-15(e) under the Exchange Act). Based on that evaluation, the Chief Executive Officer and Chief Financial Officer concluded that the design and operation of these disclosure controls and procedures were effective in ensuring that information required to be disclosed by us in reports that we file with or submit to the SEC and the Canadian Securities Administrators is recorded, processed, summarized and reported within the time periods required.

INTERNAL CONTROL OVER FINANCIAL REPORTING

Management's Annual Report on Internal Control over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting as such term is defined in the rules of the SEC and the Canadian Securities Administrators. Our internal control over financial reporting is a process designed under the supervision and with the participation of executive and financial officers to provide reasonable assurance regarding the reliability of financial reporting and the preparation of our financial statements for external reporting purposes in accordance with US GAAP.

Our internal control over financial reporting includes policies and procedures that:

- pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect transactions and dispositions of our assets;
- provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with US GAAP; and
- provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of our assets that could have a material effect on the financial statements.

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

Our management assessed the effectiveness of our internal control over financial reporting as at December 31, 2024, based on the framework established in *Internal Control – Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, our management concluded that we maintained effective internal control over financial reporting as at December 31, 2024.

During the year ended December 31, 2024, we acquired The East Ohio Gas Company, Questar Gas Company and its related Wexpro entities, and the Public Service Company of North Carolina, Incorporated. As permitted by the SEC, we excluded these acquisitions from our evaluation of the effectiveness of our internal controls over financial reporting as at December 31, 2024 because we acquired them in separate business combinations during 2024. Total assets and total revenues of The East Ohio Gas Company, Questar Gas Company and its related Wexpro entities, and Public Service Company of North Carolina, Incorporated combined represented approximately 11% and 4%, respectively, of the related consolidated financial statement amounts as of and for the year ended December 31, 2024.

The effectiveness of our internal control over financial reporting as at December 31, 2024 has been audited by PricewaterhouseCoopers LLP, Independent Registered Public Accounting Firm appointed by our shareholders. As stated in their *Report of Independent Registered Public Accounting Firm* which appears in *Item 8. Financial Statements and Supplementary Data*, they expressed an unqualified opinion on the effectiveness of our internal control over financial reporting as at December 31, 2024.

Changes in Internal Control Over Financial Reporting
During the three months ended December 31, 2024, there has been no material change in our internal control over financial reporting.

ITEM 9B. OTHER INFORMATION

OFFICERS AND DIRECTORS TRADING ARRANGEMENTS
Certain of our officers and directors have made elections to participate in, and are participating in, our compensation and benefit plans involving Enbridge stock, such as our 401(k) plan and directors' compensation plan, and may from time to time make elections which may be designed to satisfy the affirmative defense conditions of Rule 10b5-1 under the Exchange Act or may constitute non-Rule 10b5-1 trading arrangements (as defined in Item 408(c) of Regulation S-K).

ITEM 9C. DISCLOSURE REGARDING FOREIGN JURISDICTIONS THAT PREVENT INSPECTIONS

Not applicable.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Directors of Registrant
The information required by this Item will be disclosed in our Form 10-K/A, which will be filed no later than 120 days after December 31, 2024. This information will also be disclosed in the management information circular that we prepare in accordance with Canadian corporate and securities law requirements.

Executive Officers of Registrant
The information regarding executive officers is included in Part I. *Item 1. Business - Executive Officers.*

Code of Ethics for Chief Executive Officer and Senior Financial Officers
The information required by this Item will be disclosed in our Form 10-K/A, which will be filed no later than 120 days after December 31, 2024. This information will also be disclosed in the management information circular that we prepare in accordance with Canadian corporate and securities law requirements.

Insider Trading Policies and Procedures
The information required by this Item will be disclosed in our Form 10-K/A, which will be filed no later than 120 days after December 31, 2024. This information will also be disclosed in the management information circular that we prepare in accordance with Canadian corporate and securities law requirements.

ITEM 11. EXECUTIVE COMPENSATION

The information required by this Item will be disclosed in our Form 10-K/A, which will be filed no later than 120 days after December 31, 2024. This information will also be disclosed in the management information circular that we prepare in accordance with Canadian corporate and securities law requirements.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

The information required by this Item will be disclosed in our Form 10-K/A, which will be filed no later than 120 days after December 31, 2024. This information will also be disclosed in the management information circular that we prepare in accordance with Canadian corporate and securities law requirements.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

The information required by this Item will be disclosed in our Form 10-K/A, which will be filed no later than 120 days after December 31, 2024. This information will also be disclosed in the management information circular that we prepare in accordance with Canadian corporate and securities law requirements.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

The information required by this Item will be disclosed in our Form 10-K/A, which will be filed no later than 120 days after December 31, 2024. This information will also be disclosed in the management information circular that we prepare in accordance with Canadian corporate and securities law requirements.

PART IV

ITEM 15. EXHIBIT AND FINANCIAL STATEMENT SCHEDULES

(a) Consolidated Financial Statements, Supplemental Financial Data and Supplemental Schedules included in Part II of this annual report are as follows:

Enbridge Inc.:

Report of Independent Registered Public Accounting Firm (PCAOB ID 271)
Consolidated Statements of Earnings
Consolidated Statements of Comprehensive Income
Consolidated Statements of Changes in Equity
Consolidated Statements of Cash Flows
Consolidated Statements of Financial Position
Notes to the Consolidated Financial Statements

All schedules are omitted because they are not required or because the required information is included in the Consolidated Financial Statements or Notes.

(b) Exhibits:

Reference is made to the “Index of Exhibits” following *Item 16. Form 10-K Summary*, which is hereby incorporated into this Item.

ITEM 16. FORM 10-K SUMMARY

Not applicable.

INDEX OF EXHIBITS

Each exhibit identified below is included as a part of this annual report. Exhibits included in this filing are designated by an asterisk ("*"); all exhibits not so designated are incorporated by reference to a prior filing as indicated. Exhibits designated with a "+" constitute a management contract or compensatory plan arrangement.

Exhibit No.		Name of Exhibit
2.1		Purchase and Sale Agreement, dated as of September 5, 2023, by and between Dominion Energy, Inc. and Enbridge Elephant Holdings, LLC (incorporated by reference to Exhibit 2.1 to Enbridge's Form 10-Q filed November 3, 2023)
2.2		Purchase and Sale Agreement, dated as of September 5, 2023, by and between Dominion Energy, Inc. and Enbridge Parrot Holdings, LLC (incorporated by reference to Exhibit 2.2 to Enbridge's Form 10-Q filed November 3, 2023)
2.3		Purchase and Sale Agreement, dated as of September 5, 2023, by and between Dominion Energy, Inc. and Enbridge Quail Holdings, LLC (incorporated by reference to Exhibit 2.3 to Enbridge's Form 10-Q filed November 3, 2023)
3.1		Articles of Continuance of the Corporation, dated December 15, 1987 (incorporated by reference to Exhibit 2.1(a) to Enbridge's Registration Statement on Form S-8 filed May 7, 2001)
3.2		Certificate of Amendment, dated August 2, 1989, to the Articles of the Corporation (incorporated by reference to Exhibit 2.1(b) to Enbridge's Registration Statement on Form S-8 filed May 7, 2001)
3.3		Articles of Amendment of the Corporation, dated April 30, 1992 (incorporated by reference to Exhibit 2.1(c) to Enbridge's Registration Statement on Form S-8 filed May 7, 2001)
3.4		Articles of Amendment of the Corporation, dated July 2, 1992 (incorporated by reference to Exhibit 2.1(d) to Enbridge's Registration Statement on Form S-8 filed May 7, 2001)
3.5		Articles of Amendment of the Corporation, dated August 6, 1992 (incorporated by reference to Exhibit 2.1(e) to Enbridge's Registration Statement on Form S-8 filed May 7, 2001)
3.6		Articles of Arrangement of the Corporation dated December 18, 1992, attaching the Arrangement Agreement, dated December 15, 1992 (incorporated by reference to Exhibit 2.1(f) to Enbridge's Registration Statement on Form S-8 filed May 7, 2001)
3.7		Certificate of Amendment of the Corporation (notarial certified copy), dated December 18, 1992 (incorporated by reference to Exhibit 2.1(g) to Enbridge's Registration Statement on Form S-8 filed May 7, 2001)
3.8		Articles of Amendment of the Corporation, dated May 5, 1994 (incorporated by reference to Exhibit 2.1(h) to Enbridge's Registration Statement on Form S-8 filed May 7, 2001)
3.9		Certificate of Amendment, dated October 7, 1998 (incorporated by reference to Exhibit 2.1(i) to Enbridge's Registration Statement on Form S-8 filed May 7, 2001)
3.10		Certificate of Amendment, dated November 24, 1998 (incorporated by reference to Exhibit 2.1(j) to Enbridge's Registration Statement on Form S-8 filed May 7, 2001)
3.11		Certificate of Amendment, dated April 29, 1999 (incorporated by reference to Exhibit 2.1(k) to Enbridge's Registration Statement on Form S-8 filed May 7, 2001)
3.12		Certificate of Amendment, dated May 5, 2005 (incorporated by reference to Exhibit 2.1(l) to Enbridge's Registration Statement on Form S-8 filed August 5, 2005)

3.13		Certificate of Amendment, dated May 11, 2011 (incorporated by reference to Exhibit 3.13 to Enbridge's Registration Statement on Form F-4 filed September 23, 2017)
3.14		Certificate of Amendment, dated September 28, 2011 (incorporated by reference to Exhibit 3.14 to Enbridge's Registration Statement on Form F-4 filed September 23, 2017)
3.15		Certificate of Amendment, dated November 21, 2011 (incorporated by reference to Exhibit 3.15 to Enbridge's Registration Statement on Form F-4 filed September 23, 2017)
3.16		Certificate of Amendment, dated January 16, 2012 (incorporated by reference to Exhibit 3.16 to Enbridge's Registration Statement on Form F-4 filed September 23, 2017)
3.17		Certificate of Amendment, dated March 27, 2012 (incorporated by reference to Exhibit 3.17 to Enbridge's Registration Statement on Form F-4 filed September 23, 2017)
3.18		Certificate of Amendment, dated April 16, 2012 (incorporated by reference to Exhibit 3.18 to Enbridge's Registration Statement on Form F-4 filed September 23, 2017)
3.19		Certificate of Amendment, dated May 17, 2012 (incorporated by reference to Exhibit 3.19 to Enbridge's Registration Statement on Form F-4 filed September 23, 2017)
3.20		Certificate of Amendment, dated July 12, 2012 (incorporated by reference to Exhibit 3.20 to Enbridge's Registration Statement on Form F-4 filed September 23, 2017)
3.21		Certificate of Amendment, dated September 11, 2012 (incorporated by reference to Exhibit 3.21 to Enbridge's Registration Statement on Form F-4 filed September 23, 2017)
3.22		Certificate of Amendment, dated December 3, 2012 (incorporated by reference to Exhibit 3.22 to Enbridge's Registration Statement on Form F-4 filed September 23, 2017)
3.23		Certificate of Amendment, dated March 25, 2013 (incorporated by reference to Exhibit 3.23 to Enbridge's Registration Statement on Form F-4 filed September 23, 2017)
3.24		Certificate of Amendment, dated June 4, 2013 (incorporated by reference to Exhibit 3.24 to Enbridge's Registration Statement on Form F-4 filed September 23, 2017)
3.25		Certificate of Amendment, dated September 25, 2013 (incorporated by reference to Exhibit 3.25 to Enbridge's Registration Statement on Form F-4 filed September 23, 2017)
3.26		Certificate of Amendment, dated December 10, 2013 (incorporated by reference to Exhibit 3.26 to Enbridge's Registration Statement on Form F-4 filed September 23, 2017)
3.27		Certificate of Amendment, dated March 10, 2014 (incorporated by reference to Exhibit 3.27 to Enbridge's Registration Statement on Form F-4 filed September 23, 2017)
3.28		Certificate of Amendment, dated May 20, 2014 (incorporated by reference to Exhibit 3.28 to Enbridge's Registration Statement on Form F-4 filed September 23, 2017)
3.29		Certificate of Amendment, dated July 15, 2014 (incorporated by reference to Exhibit 3.29 to Enbridge's Registration Statement on Form F-4 filed September 23, 2017)
3.30		Certificate of Amendment, dated September 19, 2014 (incorporated by reference to Exhibit 3.30 to Enbridge's Registration Statement on Form F-4 filed September 23, 2017)
3.31		Certificate of Amendment, dated November 22, 2016 (incorporated by reference to Enbridge's Report of Foreign Issuer on Form 6-K filed December 1, 2016)
3.32		Certificate of Amendment, dated December 15, 2016 (incorporated by reference to Enbridge's Report of Foreign Issuer on Form 6-K filed December 16, 2016)
3.33		Certificate of Amendment, dated July 13, 2017 (incorporated by reference to Enbridge's Report of Foreign Issuer on Form 6-K filed July 13, 2017)

3.34		Certificate of Amendment, dated September 25, 2017 (incorporated by reference to Exhibit 3.34 to Enbridge's Annual Report on Form 10-K filed February 16, 2018)
3.35		Certificate of Amendment, dated December 7, 2017 (incorporated by reference to Exhibit 3.35 to Enbridge's Annual Report on Form 10-K filed February 16, 2018)
3.36		Certificate of Amendment, dated February 27, 2018 (incorporated by reference to Exhibit 3.1 to Enbridge's Current Report on Form 8-K filed March 1, 2018)
3.37		Certificate of Amendment, dated April 9, 2018 (incorporated by reference to Exhibit 3.1 to Enbridge's Current Report on Form 8-K filed April 12, 2018)
3.38		Certificate of Amendment, dated April 10, 2018 (incorporated by reference to Exhibit 3.1 to Enbridge's Current Report on Form 8-K filed April 12, 2018)
3.39		Certificate and Articles of Amendment, dated July 6, 2020 (incorporated by reference to Exhibit 3.1 to Enbridge's Current Report on Form 8-K filed July 8, 2020)
3.40		Certificate of Amendment, dated January 17, 2022 (incorporated by reference to Exhibit 3.1 to Enbridge's Current Report on Form 8-K filed January 20, 2022)
3.41		Certificate of Amendment, dated September 15, 2022 (incorporated by reference to Exhibit 3.1 to Enbridge's Current Report on Form 8-K filed September 20, 2022)
3.42		Certificate of Amendment, dated September 15, 2022 (incorporated by reference to Exhibit 3.2 to Enbridge's Current Report on Form 8-K filed September 20, 2022)
3.43		Certificate and Articles of Amendment dated September 21, 2023, relating to the Series 2023-A Preference Shares (incorporated by reference to Exhibit 3.1 to Enbridge's Current Report on Form 8-K filed September 25, 2023)
3.44		Certificate and Articles of Amendment dated September 21, 2023, relating to the Series 2023-B Preference Shares (incorporated by reference to Exhibit 3.2 to Enbridge's Current Report on Form 8-K filed September 25, 2023)
3.45		Certificate and Articles of Amendment dated September 28, 2023, relating to the Series 2023-C Conversion Preference Shares (incorporated by reference to Exhibit 3.1 to Enbridge's Current Report on Form 8-K filed October 2, 2023)
3.46		Certificate and Articles of Amendment dated September 28, 2023, relating to the Series 2023-D Conversion Preference Shares (incorporated by reference to Exhibit 3.2 to Enbridge's Current Report on Form 8-K filed October 2, 2023)
3.47		General By-Law No. 1 of Enbridge Inc. (incorporated by reference to Exhibit 3.40 to Enbridge's Form 10-K filed February 11, 2022)
3.48		By-Law No. 2 of Enbridge Inc. (incorporated by reference to Enbridge's Current Report on Form 6-K filed December 5, 2014)
4.1		Form of Indenture between Enbridge Inc. and Deutsche Bank Trust Company Americas to be dated February 25, 2005 (incorporated by reference to Exhibit 7.1 to Enbridge's Registration Statement on Form F-10 filed February 4, 2005)
4.2		First Supplemental Indenture between Enbridge Inc. and Deutsche Bank Trust Company Americas, dated March 1, 2012 (incorporated by reference to Exhibit 7.3 to Enbridge's Registration Statement on Form F-10 filed May 11, 2012)
4.3		Second Supplemental Indenture between Enbridge Inc. and Deutsche Bank Trust Company Americas, dated December 19, 2016 (incorporated by reference to Enbridge's Report of Foreign Issuer on Form 6-K filed December 20, 2016)
4.4		Third Supplemental Indenture between Enbridge Inc. and Deutsche Bank Trust Company Americas, dated July 14, 2017 (incorporated by reference to Enbridge's Report of Foreign Issuer on Form 6-K filed July 14, 2017)
4.5		Fourth Supplemental Indenture between Enbridge Inc. and Deutsche Bank Trust Company Americas, dated March 1, 2018 (incorporated by reference to Enbridge's Current Report on Form 8-K filed March 1, 2018)

4.6		Sixth Supplemental Indenture between Enbridge Inc., Spectra Energy Partners, LP (as guarantor), Enbridge Energy Partners, L.P. (as guarantor) and Deutsche Bank Trust Company Americas, dated May 13, 2019 (incorporated by reference to Enbridge's Registration Statement on Form S-3 filed May 17, 2019)
4.7		Seventh Supplemental Indenture to the Indenture between Enbridge Inc. and Deutsche Bank Trust Company Americas, dated July 8, 2020 (incorporated by reference to Exhibit 4.1 to Enbridge's Current Report on Form 8-K filed July 8, 2020)
4.8		Eighth Supplemental Indenture to the Indenture between Enbridge Inc. and Deutsche Bank Trust Company Americas, dated June 28, 2021 (incorporated by reference to Exhibit 4.4 to Enbridge's Current Report on Form 8-K filed June 28, 2021)
4.9		Ninth Supplemental Indenture to the Indenture between Enbridge Inc. and Deutsche Bank Trust Company Americas, dated September 20, 2022 (incorporated by reference to Exhibit 4.1 to Enbridge's Current Report on Form 8-K filed September 20, 2022)
4.10		Tenth Supplemental Indenture to the Indenture between Enbridge Inc. and Deutsche Bank Trust Company Americas, dated September 20, 2022 (incorporated by reference to Exhibit 4.2 to Enbridge's Current Report on Form 8-K filed September 20, 2022)
4.11		Eleventh Supplemental Indenture between Enbridge Inc. and Deutsche Bank Trust Company Americas, dated September 25, 2023 (incorporated by reference to Exhibit 4.1 to Enbridge's current Report on Form 8-K Filed September 25, 2023)
4.12		Twelfth Supplemental Indenture between Enbridge Inc. and Deutsche Bank Trust Company Americas, dated September 25, 2023 (incorporated by reference to Exhibit 4.2 to Enbridge's current Report on Form 8-K Filed September 25, 2023)
4.13		Thirteenth Supplemental Indenture between Enbridge Inc. and Deutsche Bank Trust Company Americas, dated as of June 27, 2024 (incorporated by reference to Exhibit 4.1 to Enbridge's current Report on Form 8-K filed June 27, 2024)
4.14		Fourteenth Supplemental Indenture between Enbridge Inc. and Deutsche Bank Trust Company Americas, dated June 27, 2024 (incorporated by reference to Exhibit 4.2 to Enbridge's current Report on Form 8-K filed June 27, 2024)
4.15		Shareholder Rights Plan Agreement between Enbridge Inc. and Computershare Trust Company of Canada dated as of November 9, 1995 and Amended and Restated as of May 3, 2023 (incorporated by reference to Exhibit 4.1 to Enbridge's Current Report on Form 8-K filed May 4, 2023)
4.16	*	Description of Securities Registered Under Section 12 of the Securities Exchange Act, as amended
		Certain instruments defining the rights of holders of long-term debt securities of the Registrant and its subsidiaries are omitted pursuant to Item 601(b)(4)(iii) of Regulation S-K. The Registrant hereby undertakes to furnish to the SEC, upon request, copies of any such instruments.
10.1		Enbridge Pipelines Inc. Competitive Toll Settlement dated July 1, 2011 (incorporated by reference to Exhibit 10.1 to Enbridge's Annual Report on Form 10-K filed February 16, 2018)
10.2		Enbridge Pipelines Inc. Mainline Tolling Settlement dated December 15, 2023 (incorporated by reference to Exhibit 10.1 to Enbridge's current Report on Form 8-K filed March 8, 2024)
10.3		Sixteenth Supplemental Indenture dated as of January 22, 2019 between Enbridge Energy Partners, L.P. and US Bank National Association, as trustee (incorporated by reference as Exhibit 4.1 to Enbridge's Current Report on Form 8-K filed January 24, 2019)

10.4		Seventeenth Supplemental Indenture dated as of January 22, 2019 between Enbridge Energy Partners, L.P., Enbridge Inc. and US Bank National Association, as trustee (incorporated by reference as Exhibit 4.2 to Enbridge's Current Report on Form 8-K filed January 24, 2019)
10.5		Seventh Supplemental Indenture dated as of January 22, 2019 between Spectra Energy Partners, LP, Enbridge Inc. and Wells Fargo Bank, National Association, as trustee (incorporated by reference as Exhibit 4.3 to Enbridge's Current Report on Form 8-K filed January 24, 2019)
10.6		Eighth Supplemental Indenture dated as of January 22, 2019 between Spectra Energy Partners, LP, Enbridge Inc. and Wells Fargo Bank, National Association, as trustee (incorporated by reference as Exhibit 4.4 to Enbridge's Current Report on Form 8-K filed January 24, 2019)
10.7		Subsidiary Guarantee Agreement dated as of January 22, 2019 between Spectra Energy Partners, LP and Enbridge Energy Partners, L.P. (incorporated by reference as Exhibit 4.5 to Enbridge's Current Report on Form 8-K filed January 24, 2019)
10.8	+	Form of Executive Employment Agreement (pre-2014) (incorporated by reference to Exhibit 10.2 to Enbridge's Annual Report on Form 10-K filed February 16, 2018)
10.9	+	Form of Executive Employment Agreement (2014-2016) (incorporated by reference to Exhibit 10.3 to Enbridge's Annual Report on Form 10-K filed February 16, 2018)
10.10	+	Form of Executive Employment Agreement (2017) (incorporated by reference to Exhibit 10.4 to Enbridge's Annual Report on Form 10-K filed February 16, 2018)
10.11	+	Executive Employment Agreement between Enbridge Employee Services, Inc. and William T. Yardley, dated July 25, 2018 (incorporated by reference to Exhibit 10.1 to Enbridge's Form 8-K filed July 27, 2018)
10.12	+	Form of Executive Employment Agreement (2022) with Enbridge Employee Services, Inc. (incorporated by reference to Exhibit 10.1 to Enbridge's Form 10-Q filed on July 29, 2022)
10.13	+	Form of Executive Employment Agreement (2023) with Enbridge Employee Services, Inc. (incorporated by reference to Exhibit 10.1 of Enbridge's Current Report on Form 8-K Amendment No. 2 filed March 20, 2023)
10.14	+	Form of Indemnification Agreement (2015) (director or officer) (incorporated by reference to Exhibit 10.11 to Enbridge's Annual Report on Form 10-K filed February 15, 2019)
10.15	+	Enbridge Inc. 2019 Long Term Incentive Plan (incorporated by reference to Appendix A to Enbridge's Proxy Statement on Schedule 14A for Enbridge's Annual Meeting of Shareholders (File No. 001-15254) filed March 27, 2019)
10.16	+	Form of Enbridge Inc. 2019 Long-Term Incentive Plan Restricted Stock Unit Grant Notice and Restricted Grant Unit Award Agreement (Share-settled) – Retention Award Version (incorporated by reference to Exhibit 99.1 to Enbridge's 8-K filed November 30, 2022)
10.17	+	Form of Enbridge Inc. 2019 Long Term Incentive Plan Stock Option Grant Notice and Stock Option Award Agreement (2021) (incorporated by reference to Exhibit 10.1 to Enbridge's Form 10-Q filed May 7, 2021)
10.18	+	Form of Enbridge Inc. 2019 Long Term Incentive Plan Performance Stock Unit Grant Notice and Performance Stock Unit Award Agreement (2021) (incorporated by reference to Exhibit 10.2 to Enbridge's Form 10-Q filed May 7, 2021)
10.19	+	Form of Enbridge Inc. 2019 Long Term Incentive Plan Restricted Stock Unit Grant Notice and Restricted Stock Unit Award Agreement (2021 Share-settled) (incorporated by reference to Exhibit 10.3 to Enbridge's Form 10-Q filed May 7, 2021)

10.20	+	Form of Enbridge Inc. 2019 Long Term Incentive Plan Restricted Stock Unit Grant Notice and Restricted Stock Unit Award Agreement (2021 Cash-settled) (incorporated by reference to Exhibit 10.4 to Enbridge's Form 10-Q filed May 7, 2021)
10.21	+	Form of Enbridge Inc. 2019 Long Term Incentive Plan Restricted Stock Unit - Energy Marketers Grant Notice and Restricted Stock Unit Award Agreement (2021) (incorporated by reference to Exhibit 10.5 to Enbridge's Form 10-Q filed May 7, 2021)
10.22	+	Form of Enbridge Inc. 2019 Long Term Incentive Plan Stock Option Grant Notice and Stock Option Award Agreement (2020) (incorporated by reference to Exhibit 10.1 to Enbridge's Form 10-Q filed May 7, 2020)
10.23	+	Form of Enbridge Inc. 2019 Long Term Incentive Plan Performance Stock Unit Grant Notice and Performance Stock Unit Award Agreement (2020) (incorporated by reference to Exhibit 10.2 to Enbridge's Form 10-Q filed May 7, 2020)
10.24	+	Form of Enbridge Inc. 2019 Long Term Incentive Plan Restricted Stock Unit Grant Notice and Restricted Stock Unit Award Agreement (2020 Share-settled) (incorporated by reference to Exhibit 10.3 to Enbridge's Form 10-Q filed May 7, 2020)
10.25	+	Form of Enbridge Inc. 2019 Long Term Incentive Plan Restricted Stock Unit Grant Notice and Restricted Stock Unit Award Agreement (2020 Cash-settled) (incorporated by reference to Exhibit 10.4 to Enbridge's Form 10-Q filed May 7, 2020)
10.26	+	Form of Enbridge Inc. 2019 Long Term Incentive Plan Stock Option Grant Notice and Stock Option Award Agreement (incorporated by reference to Exhibit 10.4 to Enbridge's Form 10-Q filed May 10, 2019)
10.27	+	Form of Enbridge Inc. 2019 Long Term Incentive Plan Performance Stock Unit Grant Notice and Performance Stock Unit Award Agreement (incorporated by reference to Exhibit 10.5 to Enbridge's Form 10-Q filed May 10, 2019)
10.28	+	Form of Enbridge Inc. 2019 Long Term Incentive Plan Restricted Stock Unit Grant Notice and Restricted Stock Unit Award Agreement (incorporated by reference to Exhibit 10.6 to Enbridge's Form 10-Q filed May 10, 2019)
10.29	+	Form of Enbridge Inc. 2019 Long Term Incentive Plan Restricted Stock Unit - Energy Marketers Grant Notice and Restricted Stock Unit Award Agreement (incorporated by reference to Exhibit 10.7 to Enbridge's Form 10-Q filed May 10, 2019)
10.30	+	Form of Enbridge Inc. 2019 Long Term Incentive Plan Restricted Stock Unit Grant Notice and Restricted Stock Unit Award Agreement - Retention Award Version (incorporated by reference to Exhibit 10.8 to Enbridge's Form 10-Q filed August 2, 2019)
10.31	+	Enbridge Inc. Incentive Stock Option Plan (2007), as amended and restated (2011) (incorporated by reference to Exhibit 10.13 to Enbridge's Annual Report on Form 10-K filed February 16, 2018)
10.32	+	Enbridge Inc. Incentive Stock Option Plan (2007), as amended and restated (2011 and 2014) (incorporated by reference to Exhibit 10.14 to Enbridge's Annual Report on Form 10-K filed February 16, 2018)
10.33	+	Enbridge Inc. Incentive Stock Option Plan (2007), as revised (incorporated by reference to Exhibit 10.15 to Enbridge's Annual Report on Form 10-K filed February 16, 2018)
10.34	+	Enbridge Inc. Directors' Compensation Plan dated February 8, 2023, effective January 1, 2023 (incorporated by reference to Exhibit 10.1 to Enbridge's Form 10-Q filed May 5, 2023)
10.35	+	Enbridge Inc. Directors' Compensation Plan dated February 9, 2021, effective April 1, 2021 (incorporated by reference to Exhibit 10.6 to Enbridge's Form 10-Q filed May 7, 2021)

10.36	+	Enbridge Inc. Directors' Compensation Plan dated February 11, 2020, effective January 1, 2020 (incorporated by reference to Exhibit 10.1 to Enbridge's Form 10-Q filed July 29, 2020)
10.37	+	Enbridge Inc. Directors' Compensation Plan dated February 14, 2018 Amended Effective February 12, 2019 (incorporated by reference to Exhibit 10.2 to Enbridge's Form 10-Q filed May 10, 2019)
10.38	+	Enbridge Inc. Directors' Compensation Plan dated February 14, 2018, effective January 1, 2018 (incorporated by reference as Exhibit 10.3 to Enbridge's Form 10-Q filed May 10, 2018)
10.39	+	Enbridge Inc. Directors' Compensation Plan, dated November 3, 2015, effective January 1, 2016 (incorporated by reference as Exhibit 10.16 to Enbridge's Form 10-K filed February 16, 2018)
10.40	+	Enbridge Inc. Short Term Incentive Plan (As Amended and Restated Effective January 1, 2023) (incorporated by reference to Exhibit 10.39 to Enbridge's Form 10-K filed February 9, 2024)
10.41	+	Enbridge Inc. Short Term Incentive Plan (As Amended and Restated Effective January 1, 2019) (incorporated by reference to Exhibit 10.1 to Enbridge's Form 10-Q filed May 10, 2019)
10.42	+	Enbridge Supplemental Pension Plan (As Amended and Restated Effective January 1, 2018) (incorporated by reference as Exhibit 10.1 to Enbridge's Quarterly Report on Form 10-Q filed May 10, 2018)
10.43	*+	Amendment 1 to Enbridge Supplemental Pension Plan (As Amended and Restated Effective January 1, 2018)
10.44	+	Enbridge Supplemental Pension Plan for United States Employees (As Amended and Restated Effective January 1, 2005) (incorporated by reference to Exhibit 10.20 to Enbridge's Annual Report on Form 10-K filed February 16, 2018)
10.45	+	Amendment 1 and Amendment 2 to the Enbridge Supplemental Pension Plan for United States Employees (As Amended and Restated Effective January 1, 2005) (incorporated by reference to Exhibit 10.21 to Enbridge's Annual Report on Form 10-K filed February 16, 2018)
10.46	+	Third Amendment to The Enbridge Supplemental Pension Plan for United States Employees (As Amended and Restated Effective January 1, 2005) (incorporated by reference to Exhibit 10.2 to Enbridge's Quarterly Report on Form 10-Q filed May 10, 2018)
10.47	+	Fourth Amendment to The Enbridge Supplemental Pension Plan for United States Employees (As Amended and Restated Effective January 1, 2005) (incorporated by reference to Exhibit 10.42 to Enbridge's Annual Report on Form 10-K filed February 10, 2023)
10.48	+	Fifth Amendment to The Enbridge Supplemental Pension Plan for United States Employees (As Amended and Restated Effective January 1, 2005) (incorporated by reference to Exhibit 10.43 to Enbridge's Annual Report on Form 10-K filed February 10, 2023)
10.49	+	Spectra Energy Corp Directors' Savings Plan, as amended and restated (incorporated by reference to Exhibit 10.22 to Enbridge's Annual Report on Form 10-K filed February 16, 2018)
10.50	+	Spectra Energy Corp Executive Savings Plan, as amended and restated (incorporated by reference to Exhibit 10.23 to Enbridge's Annual Report on Form 10-K filed February 16, 2018)
10.51	+	Spectra Energy Executive Cash Balance Plan, as amended and restated (incorporated by reference to Exhibit 10.24 to Enbridge's Annual Report on Form 10-K filed February 16, 2018)

10.52	+	Omnibus Amendment, dated June 20, 2014, to Spectra Energy Corp Executive Savings Plan, Spectra Energy Corp Executive Cash Balance Plan and Spectra Energy Corp 2007 Long-Term Incentive Plan (incorporated by reference to Exhibit 10.25 to Enbridge's Annual Report on Form 10-K filed February 16, 2018)
10.53	+	Form of Spectra Energy Corp Stock Option Agreement (Nonqualified Stock Options) (2016) pursuant to the Spectra Energy Corp 2007 Long-Term Incentive Plan (incorporated by reference to Exhibit 10.28 to Enbridge's Annual Report on Form 10-K filed February 16, 2018)
10.54	+	Spectra Energy Corp 2007 Long-Term Incentive Plan (as amended and restated) (incorporated by reference to Exhibit 10.32 to Enbridge's Annual Report on Form 10-K filed February 16, 2018)
10.55	+	Second Amendment to the Spectra Energy Corp Executive Savings Plan (As Amended and Restated Effective May 1, 2012) (incorporated by reference to Exhibit 10.36 to Enbridge's Annual Report on Form 10-K filed February 16, 2018)
10.56	+	Second Amendment to the Spectra Energy Corp Executive Cash Balance Plan (As Amended and Restated Effective May 1, 2012) (incorporated by reference to Exhibit 10.37 to Enbridge's Annual Report on Form 10-K filed February 16, 2018)
19.1	*	Enbridge Inc. Insider Trading Guidelines
21.1	*	Subsidiaries of the Registrant
22.1	*	Subsidiary Guarantors
23.1	*	Consent of PricewaterhouseCoopers LLP
24.1		Powers of Attorney (included on the signature page of the Annual Report)
31.1	*	Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2	*	Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1	*	Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2	*	Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
97.1	+	Enbridge Inc. Clawback Policy for the Mandatory Recovery of Erroneously Awarded Incentive-Based Compensation (incorporated by reference to Exhibit 97.1 to Enbridge's Annual Report on Form 10-K filed February 9, 2024)
101	*	Inline XBRL Document Set for the consolidated financial statements and accompanying notes in Part II. Item 8 "Financial Statements and Supplementary Data" of this Annual Report on Form 10-K
104	*	Cover Page Interactive Date File – the cover page XBRL tags are embedded within the Inline XBRL document (included in Exhibit 101).

SIGNATURES

POWER OF ATTORNEY

Each person whose signature appears below appoints Reginald D. Hedgebeth, Patrick R. Murray and David Taniguchi, and each of them, any of whom may act without the joinder of the other, as their true and lawful attorneys-in-fact and agents, with full power of substitution, for him or her and in his or her name, place and stead, in any and all capacities, to sign any and all amendments to this Annual Report of Enbridge on Form 10-K, and to file the same, with all exhibits thereto, and all other documents in connection therewith, with the Securities and Exchange Commission, granting unto said attorneys-in-fact and agents, and each of them, full power and authority to do and perform each and every act and thing requisite and necessary to be done, as fully to all intents and purposes as he or she might or would do in person, hereby ratifying and confirming all that said attorneys-in-fact and agents or any of them or their or his or her substitute and substitutes, may lawfully do or cause to be done by virtue hereof.

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

ENBRIDGE INC.
(Registrant)

Date: February 14, 2025

By: **/s/ Gregory L. Ebel**
Gregory L. Ebel
President and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below on February 14, 2025 by the following persons on behalf of the registrant and in the capacities indicated.

/s/ Gregory L. Ebel Gregory L. Ebel President and Chief Executive Officer (Principal Executive Officer)	**/s/ Patrick R. Murray** Patrick R. Murray Executive Vice President and Chief Financial Officer (Principal Financial Officer)
/s/ Melissa M. LaForge Melissa M. LaForge Senior Vice President and Chief Accounting Officer (Principal Accounting Officer)	**/s/ Pamela L. Carter** Pamela L. Carter Chair of the Board of Directors
/s/ Mayank (Mike) M. Ashar Mayank (Mike) M. Ashar Director	**/s/ Gaurdie E. Banister** Gaurdie E. Banister Director
/s/ Susan M. Cunningham Susan M. Cunningham Director	**/s/ Jason B. Few** Jason B. Few Director
/s/ Douglas L. Foshee Douglas L. Foshee Director	**/s/ Theresa B.Y. Jang** Theresa B.Y. Jang Director
/s/ Teresa S. Madden Teresa S. Madden Director	**/s/ Manjit Minhas** Manjit Minhas Director
/s/ Stephen S. Poloz Stephen S. Poloz Director	**/s/ S. Jane Rowe** S. Jane Rowe Director
/s/ Steven W. Williams Steven W. Williams Director	

Investor information

Investor inquiries

If you have inquiries regarding the following:

- The latest news releases or investor presentations
- Any investment-related inquiries

Please contact Enbridge Investor Relations
Toll-free: 1-800-481-2804
investor.relations@enbridge.com

Enbridge Inc.
200, 425 – 1 Street S.W.
Calgary, Alberta, Canada T2P 3L8

Annual Meeting

The Annual Meeting of Shareholders will be held on May 7, 2025 at 1:30 p.m. MT. The Meeting will be held virtually via live audio webcast. A replay will be available on enbridge.com. Webcast details will be available on the Company's website closer to the Meeting date.

Registrar and Transfer Agent

For information relating to registered shareholdings, dividends, direct dividend deposit and lost certificates, please contact:

Computershare Trust Company of Canada
100 University Avenue, 8th Floor
Toronto, Ontario M5J 2Y1

Toll-free North America: 1-866-276-9479
Outside North America: 1-514-982-8696
computershare.com/enbridge

Auditors

PricewaterhouseCoopers LLP

Cover images (top to bottom):

- Silver State North solar project, Nevada
- Align Renewable Natural Gas facility, Utah
- Compressor Station 5, British Columbia
- Enbridge Ingleside Energy Center, Texas

2025 Enbridge Inc. Common Share Dividends

	Q1	Q2	Q3	Q4
Dividend	$0.9425	$ – [2]	$ – [2]	$ – [2]
Payment date	Mar 01	Jun 01	Sep 01	Dec 01
Record date[1]	Feb 14	May 15	Aug 15	Nov 14

[1] Dividend record dates for Common Shares are generally February 15, May 15, August 15 and November 15 in each year unless the 15th falls on a Saturday or Sunday.

[2] Amount will be announced as declared by the Board of Directors.

Common and Preference Shares

(as of December 31, 2024)

The Common Shares of Enbridge Inc. trade in Canada on the Toronto Stock Exchange and in the United States on the New York Stock Exchange under the trading symbol "ENB." The Preference Shares of Enbridge Inc. trade in Canada on the Toronto Stock Exchange under the trading symbols:

Series A – ENB.PR.A
Series B – ENB.PR.B
Series D – ENB.PR.D
Series F – ENB.PR.F
Series G – ENB.PR.G
Series H – ENB.PR.H
Series I – ENB.PR.I
Series L – ENB.PF.U
Series N – ENB.PR.N
Series P – ENB.PR.P
Series R – ENB.PR.T
Series 1 – ENB.PR.V
Series 3 – ENB.PR.Y
Series 4 – ENB.PR.Z
Series 5 – ENB.PF.V
Series 7 – ENB.PR.J
Series 9 – ENB.PF.A
Series 11 – ENB.PF.C
Series 13 – ENB.PF.E
Series 15 – ENB.PF.G
Series 19 – ENB.PF.K

Forward-looking information

This Annual Report includes references to forward-looking information, including with regards to our corporate vision and strategy, the supply of and demand for energy, energy transition and lower-carbon energy, ESG goals, and growth opportunities and outlook. By its nature, this information involves certain assumptions and expectations about future outcomes, so we remind you it is subject to risks and uncertainties that affect our business. The more significant factors and risks that might affect our future outcomes are listed and discussed in the "Forward-looking information" and Risk Factors sections of our Form 10-K and Management's Discussion and Analysis (MD&A), included in this Annual Report and available on both sedarplus.ca and sec.gov.

Non-GAAP and other financial measures

This Annual Report 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 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 United States of America (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 in our earnings news releases and on our website, sedarplus.ca or sec.gov.

Enbridge is committed to reducing its impact on the environment, including the production of this publication. This report was printed entirely on FSC® Certified paper.

FSC www.fsc.org MIX Paper from responsible sources FSC® C132107