ANNUAL REPORT 2025

TC Energy | ENERGY. CONNECTED.

Solid growth. Low risk.
Repeatable performance.

FINANCIAL HIGHLIGHTS

26
CONSECUTIVE YEARS OF DIVIDEND INCREASES[1]

Comparable earnings per common share[2] (dollars)

2023	3.78
2024	3.73
2025	**3.51**

Net income per common share (dollars)

2023	2.15
2024	4.05
2025	**3.47**

Comparable EBITDA[2] (millions of dollars)

2023	9,472
2024	10,049
2025	**10,952**

Segmented earnings (millions of dollars)

2023	5,097
2024	7,964
2025	**8,036**

Comparable earnings[2] (millions of dollars)

2023	3,896
2024	3,865
2025	**3,654**

Net income attributable to common shares (millions of dollars)

2023	2,217
2024	4,199
2025	**3,612**

Comparable funds generated from operations[2] (millions of dollars)*

**Includes continuing and discontinued operations. Represents nine months of Liquids Pipelines earnings in 2024 compared to a full year of Liquids Pipelines earnings in 2023. Refer to the Discontinued operations section of our 2025 Annual MD&A for additional information.*

2023	7,980
2024	7,890
2025	**7,996**

Net cash provided by operations (millions of dollars)*

**Includes continuing and discontinued operations. Represents nine months of Liquids Pipelines earnings in 2024 compared to a full year of Liquids Pipelines earnings in 2023. Refer to the Discontinued operations section of our 2025 Annual MD&A for additional information.*

2023	7,268
2024	7,696
2025	**7,346**

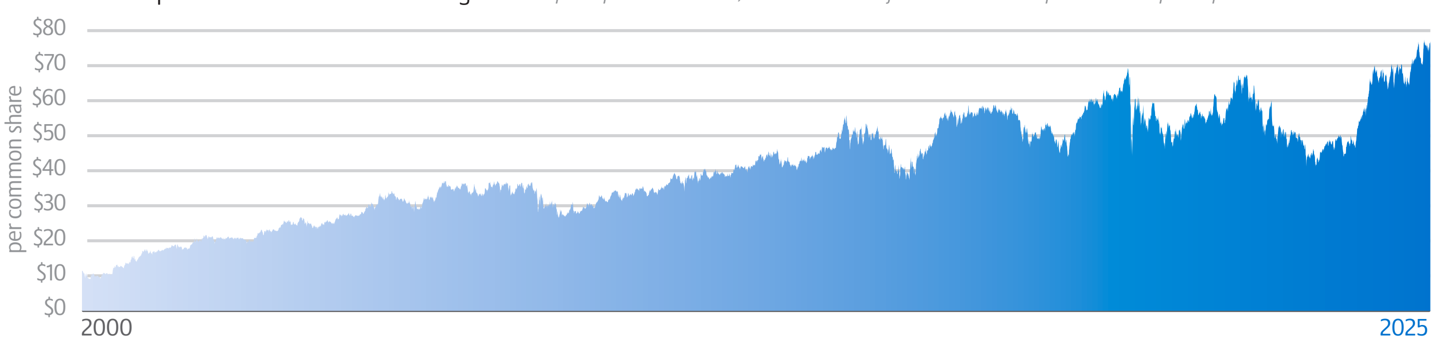
Dividends declared per common share (dollars)*

**Dividends declared in fourth quarter 2024, and thereafter, reflect TC Energy's proportionate allocation following the Spinoff Transaction. Refer to the Discontinued operations section for additional information.*

2023	3.72
2024	3.7025
2025	**3.40**

Common share price* — Toronto Stock Exchange

**Share prices prior to October 2, 2024 have been adjusted to reflect the spinoff of the Liquids Pipelines business.*



Forward-looking information *| These pages contain certain forward-looking information. For more information on forward-looking information, the assumptions made, and the risks and uncertainties which could cause actual results to differ from the anticipated results, refer to TC Energy's 2025 Annual Report filed with Canadian securities regulators and the U.S. Securities and Exchange Commission and available at TCEnergy.com.*

1 *2025 represents an increase from TC Energy's proportionate allocation of the dividend following the Spinoff Transaction.*

2 ***Non-GAAP measures*** *| Comparable EBITDA, Comparable earnings, Comparable earnings per common share and Comparable funds generated from operations are non-GAAP measures used throughout this document. These measures do not have any standardized meaning under GAAP and therefore are unlikely to be comparable to similar measures presented by other companies. The most directly comparable GAAP measures are segmented earnings (losses), net income (loss), net income (loss) per common share and net cash provided by operations, respectively. Refer to the Non-GAAP measures section of the 2025 Annual MD&A (incorporated by reference) for more information about the non-GAAP measures we use and for a reconciliation to the U.S. GAAP equivalent. Our 2025 Annual MD&A is available under TC Energy's profile on SEDAR+ at www.sedarplus.ca.*

LAND ACKNOWLEDGEMENT

TC Energy acknowledges the Indigenous ancestral lands on which the company operates across North America and affirms our commitment to understanding how the histories, cultures and rich traditions of the Peoples of these lands have been shaped by the past, how they influence our present and what we can learn to prosper together in the future. We are committed to working with the original keepers of the land to advance shared ownership and prosperity.

ABOUT TC ENERGY

WE ARE A LEADER IN NORTH AMERICAN ENERGY INFRASTRUCTURE

For almost 75 years, we have been building and operating the backbone of North America's energy system. Since our founding, we have built a solid foundation of exemplary assets, a talented workforce and valued stakeholder relationships, all guided by our commitment to safety and operational excellence.

Every day, our dedicated team proudly connects the world to the energy it needs, moving over 30 per cent of the cleaner-burning natural gas used across the continent. Complemented by strategic ownership and low-risk investments in power generation, our infrastructure fuels industries and generates affordable, reliable and sustainable power across North America, while enabling liquefied natural gas (LNG) exports to global markets.

Our business is based on the connections we make. We partner with communities, businesses and leaders across our extensive energy network to unlock opportunity today and for generations to come. Guided by our values—*safety in every step, personal accountability, one team* and *active learning*—we deliver energy that powers lives and livelihoods, while positioning North America as a global energy leader.

TC Energy's common shares trade on the Toronto (TSX) and New York (NYSE) stock exchanges under the symbol TRP.
To learn more, visit us at TCEnergy.com.

Image: Reclaimed land in British Columbia, Canada

CONFIDENCE IN OUR STRATEGY, MOMENTUM FOR THE FUTURE

A MESSAGE FROM JOHN AND FRANÇOIS

A YEAR OF DISCIPLINED DELIVERY AND MARKET MOMENTUM

This was a defining year for TC Energy—**we demonstrated the strength of our strategy and our differentiated position in the fastest-growing segments of the energy market: natural gas and power generation**. In the face of complexity and change, we continued to operate our North American natural gas and power assets safely and reliably, while delivering nation-building infrastructure. These achievements reflect our ability to adapt while staying focused on solid growth, low risk and repeatable performance.

We focused on three priorities: **maximizing the value of our assets through safety and operational excellence, executing our selective portfolio of growth projects** and **ensuring financial strength and agility**. Our disciplined approach delivered strong safety, operational and financial performance across our North American footprint.

Rising energy demand drove record utilization across our network, including 15 new pipeline flow records on our natural gas systems. We placed $8.3 billion of capital projects into service—on time and more than 15 per cent below budget—and sanctioned diverse projects with attractive risk-adjusted returns. Comparable EBITDA grew 9 per cent year-over-year and we continued to strengthen our balance sheet to stay on track toward our long-term 4.75x debt-to-EBITDA target[3], while also extending our record of a 26th consecutive year of dividend growth.

For decades, regulated and contracted cash flows have provided stability through market shifts. This foundation, backed by our focused natural gas and power portfolios, has supported consistent, repeatable performance—positioning us to meet rising energy needs and advance a more affordable and reliable energy system.

DELIVERING NATION-BUILDING INFRASTRUCTURE

Grounded in discipline and focus, we advanced critical energy infrastructure across North America that reinforced network resilience, increased available capacity and supported economic growth.

In Canada, a historic milestone was reached with the **first LNG shipment to global markets—made possible by our Coastal GasLink pipeline**, which entered service in November 2024. This milestone underscores the importance of our Canadian natural gas network in unlocking global market access. We also made strong progress in power generation. At **Bruce Power**, the team advanced Units 3 and 4 of the Major Component Replacement (MCR) program on budget and on schedule, reinforcing the team's proven ability to execute projects at a world-class nuclear facility critical to Ontario's growing need for affordable, non-emitting, reliable electricity.

In the United States (U.S.), we completed the **Virginia Reliability** and **Wisconsin Reliability** projects—strengthening system reliability, expanding capacity and reducing greenhouse gas (GHG) emissions across high-demand corridors. Together, they represent more than US$1.2 billion in investment, contributing over US$1 billion in economic output and supporting thousands of jobs.

In Mexico, the **Southeast Gateway** pipeline entered into service. Completed 13 per cent under budget, this transformative infrastructure project reflects our execution capabilities and a successful partnership with the Comisión Federal de Electricidad (CFE). This achievement marked a significant financial and operational milestone, while enhancing energy reliability and economic opportunity in Southeast Mexico.

3 Debt-to-EBITDA is a non-GAAP ratio. Adjusted debt and adjusted comparable EBITDA are used to calculate debt-to-EBITDA. This measure does not have any standardized meaning under GAAP and therefore is unlikely to be comparable to similar measures presented by other companies. We believe that debt-to-EBITDA provides investors with useful information as it reflects our ability to service our debt and other long-term commitments. Refer to TC Energy's 2025 Quarterly Report to Shareholders (Q4) for information on how debt-to-EBITDA is calculated and reconciliations of adjusted debt and adjusted comparable EBITDA for the years ended December 31, 2023, 2024 and 2025.

John Lowe

François Poirier

POWERING A GROWING ENERGY SYSTEM

Our latest forecast anticipates natural gas demand rising by 45 Bcf/d by 2035, driven by LNG growth, unprecedented power demand and coal-to-gas conversions. Across North America, electricity consumption is surging—expanding artificial intelligence (AI) and data centres, population growth and weather extremes are testing reliability. Meeting this demand requires infrastructure. Our portfolios provide that foundation—supporting a more affordable, reliable and sustainable energy system.

North America has one of the largest, most integrated energy systems in the world. Our interconnected pipelines transform three separate nations into a continent-wide energy advantage. This is about more than infrastructure—it's about strengthening North America's position as the world's most trusted energy partner.

BUILDING A STRONGER, CONNECTED FUTURE

As we turn to 2026, our strategic priorities remain unchanged—a clear signal that **our strategy is working**. We will build on this momentum with the same discipline that delivered results in 2025, leveraging our unmatched scale and focused natural gas and power portfolio to meet growing demand, strengthen North America's position as a global energy leader and deliver sustainable value for our shareholders.

In 2026, we will celebrate **75 years since our founding**—a milestone that reflects the legacy we've built as a nation-building enterprise across North America and the foundation that made us the energy leader we are today.

This progress is powered by our people. Every day, our team of more than 6,500 employees work with care and commitment to safely move, generate and store the energy that fuels homes, communities and industries across Canada, the U.S. and Mexico. Our commitment to all stakeholders is strengthened by the governance and oversight of our Board of Directors, who uphold strong principles and guide our strategic direction.

On behalf of the Board and our leadership team, we thank you for your trust and continued partnership. We are proud to connect the world to the energy it needs—and to deliver the infrastructure that powers lives and livelihoods today and for generations to come.

Sincerely,

John Lowe
Chair of the
Board of Directors

François Poirier
President and
Chief Executive Officer

OUR STRATEGY IS WORKING

DELIVERING ON OUR 2025 PRIORITIES

Through disciplined execution and strong operational performance, we advanced projects, strengthened reliability and enhanced financial resilience to position TC Energy for long-term growth.

Maximize the value of our assets through safety and operational excellence

- Maintained strong reliability and availability across our portfolio of assets with safety incident rates trending at five-year lows
- Delivered ~9 per cent comparable EBITDA growth year-over-year; comparable EBITDA in the upper end or above outlook for the last four years
- Achieved a successful settlement on the Columbia Gas rate case

Execute our selective portfolio of growth projects

- Placed over $8 billion of assets into service at ~15 per cent under budget
- Maintained on-budget and on-schedule execution for Bruce Power MCR Units 3 and 4
- Sanctioned diverse projects with attractive risk-adjusted returns

Ensure financial strength and agility

- Maintained capital discipline with net capital expenditures[4] below our targeted range of $5.5–$6.0 billion
- S&P affirmed our BBB+ credit rating and revised outlook to stable
- Continued trending towards long-term target of 4.75x debt-to-EBITDA

~9%
COMPARABLE EBITDA GROWTH YEAR-OVER-YEAR

S&P AFFIRMED OUR
BBB+ CREDIT RATING
AND REVISED TO STABLE OUTLOOK

CONTINUED TRENDING TOWARDS LONG-TERM TARGET OF
4.75x
DEBT-TO-EBITDA

4 *Net capital expenditures are adjusted for the portion attributed to non-controlling interests and is a supplementary financial measure used throughout this document. This measure does not have any standardized meaning under GAAP and therefore is unlikely to be comparable to similar measures presented by other companies. Refer to the Supplementary financial measure section of the 2025 Annual MD&A (incorporated by reference) for more information about the non-GAAP measures we use. Our 2025 Annual MD&A is available under TC Energy's profile on SEDAR+ at www.sedarplus.ca.*

OUR FOCUS FOR THE YEAR AHEAD

BUILDING ON OUR MOMENTUM FOR 2026

With a clear strategy and proven performance, we are well positioned to deliver sustainable growth and value for years to come. In 2026, our strategic priorities have not changed—demonstrating that **our strategy is working**. This year, we will continue to:

Maximize the value of our assets through safety and operational excellence

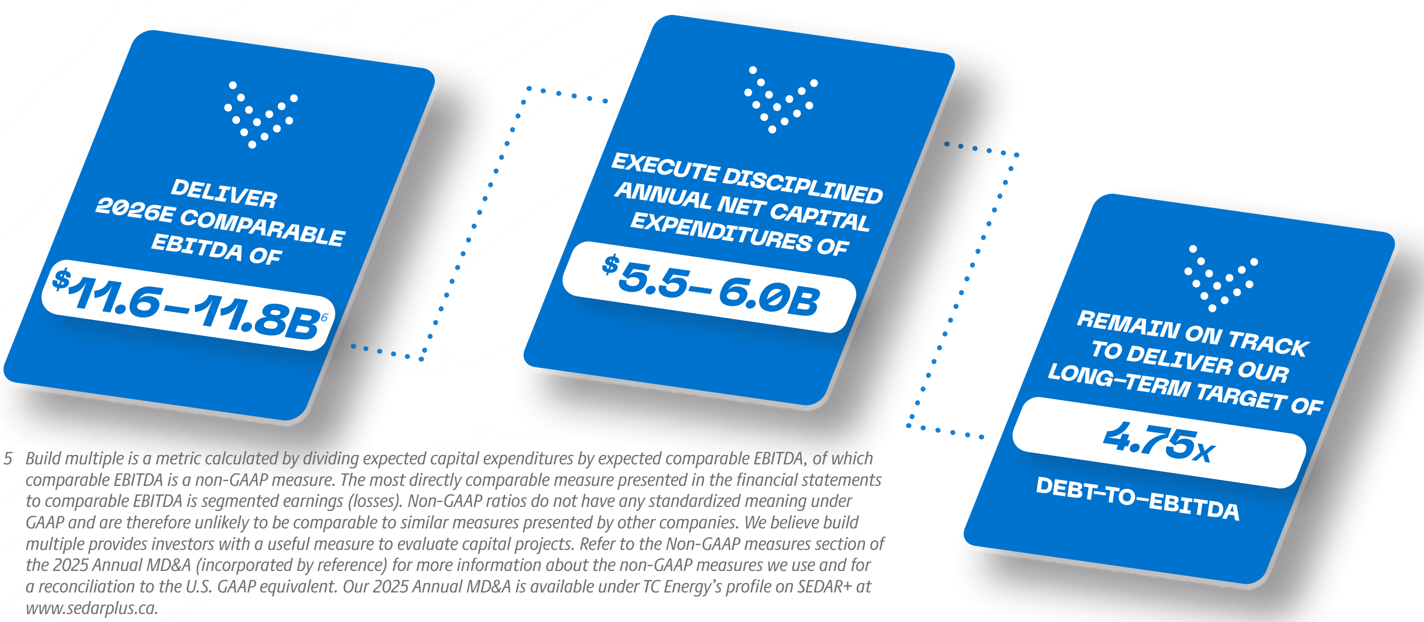
- Exceed safety targets and maximize availability of assets
- Advance integration of our Natural Gas Pipelines business to capture synergies
- Capture efficiencies through commercial and technological innovation

Execute our selective portfolio of growth projects

- Bring projects into service on time and on budget or better
- Prioritize low-risk, executable projects that maximize returns
- Allocate $6 billion of net annual capital expenditures through 2030 with build multiples[5] in the 5–7x range

Ensure financial strength and agility

- Deliver 2026E comparable EBITDA of $11.6–$11.8 billion[6]
- Execute disciplined annual net capital expenditures of $5.5–$6.0 billion
- Remain on track to deliver our long-term target of 4.75x debt-to-EBITDA



5 *Build multiple is a metric calculated by dividing expected capital expenditures by expected comparable EBITDA, of which comparable EBITDA is a non-GAAP measure. The most directly comparable measure presented in the financial statements to comparable EBITDA is segmented earnings (losses). Non-GAAP ratios do not have any standardized meaning under GAAP and are therefore unlikely to be comparable to similar measures presented by other companies. We believe build multiple provides investors with a useful measure to evaluate capital projects. Refer to the Non-GAAP measures section of the 2025 Annual MD&A (incorporated by reference) for more information about the non-GAAP measures we use and for a reconciliation to the U.S. GAAP equivalent. Our 2025 Annual MD&A is available under TC Energy's profile on SEDAR+ at www.sedarplus.ca.*

6 *Reflects USD/CAD foreign exchange rate of 1.36-1.39.*

OUR BUSINESS | CONNECTING ENERGY TO OPPORTUNITY ACROSS NORTH AMERICA

NATURAL GAS — UNIQUE AMONG OUR PEERS

Our natural gas business is a cornerstone of North America's energy security and economic strength. With one of the largest networks on the continent, we connect abundant, cost-competitive supply to growing demand across Canada, the U.S. and Mexico. Every day, our over 94,000-kilometre (58,000-mile) system moves more than 30 per cent of the natural gas consumed in North America and provides over 650 Bcf of storage capacity.

Natural gas is essential for energy reliability and affordability—and it can contribute to global GHG emissions reductions by supporting the displacement of coal and other carbon-intensive fuels. It complements renewables, supports electrification and enables industries and communities to thrive. We continue to modernize our system and work to reduce GHG emissions from our operations, with a near term focus on advancing our target to reduce methane emissions intensity by 40–55 per cent below a 2019 baseline, by 2035.

POWER AND ENERGY SOLUTIONS — SCALABLE, COMPLEMENTARY AND ANCHORED BY NUCLEAR

Our Power and Energy Solutions business strengthens grid resilience and accelerates the transition to a lower-carbon future. Anchored by our 48.3 per cent ownership in Bruce Power—which provides about 30 per cent of Ontario's electricity—our portfolio delivers reliable, affordable and non-emitting power.

With more than 4,650 megawatts of capacity—over 75 per cent from low-carbon sources—this business complements our natural gas network and supports energy stability. We are advancing long-term growth through Bruce Power's MCR program and Project 2030, and exploring pumped hydro storage and other technologies to provide flexible, lower-emission power solutions.

ONE OF ONE | OUR UNMATCHED ADVANTAGE

We continue to showcase the strength of our business and our differentiated exposure to the fastest-growing segments of the energy market—natural gas and power. This focused strategy and integrated portfolio provides us with unique competitive advantages.

UNRIVALLED CONTINENTAL CONNECTIVITY

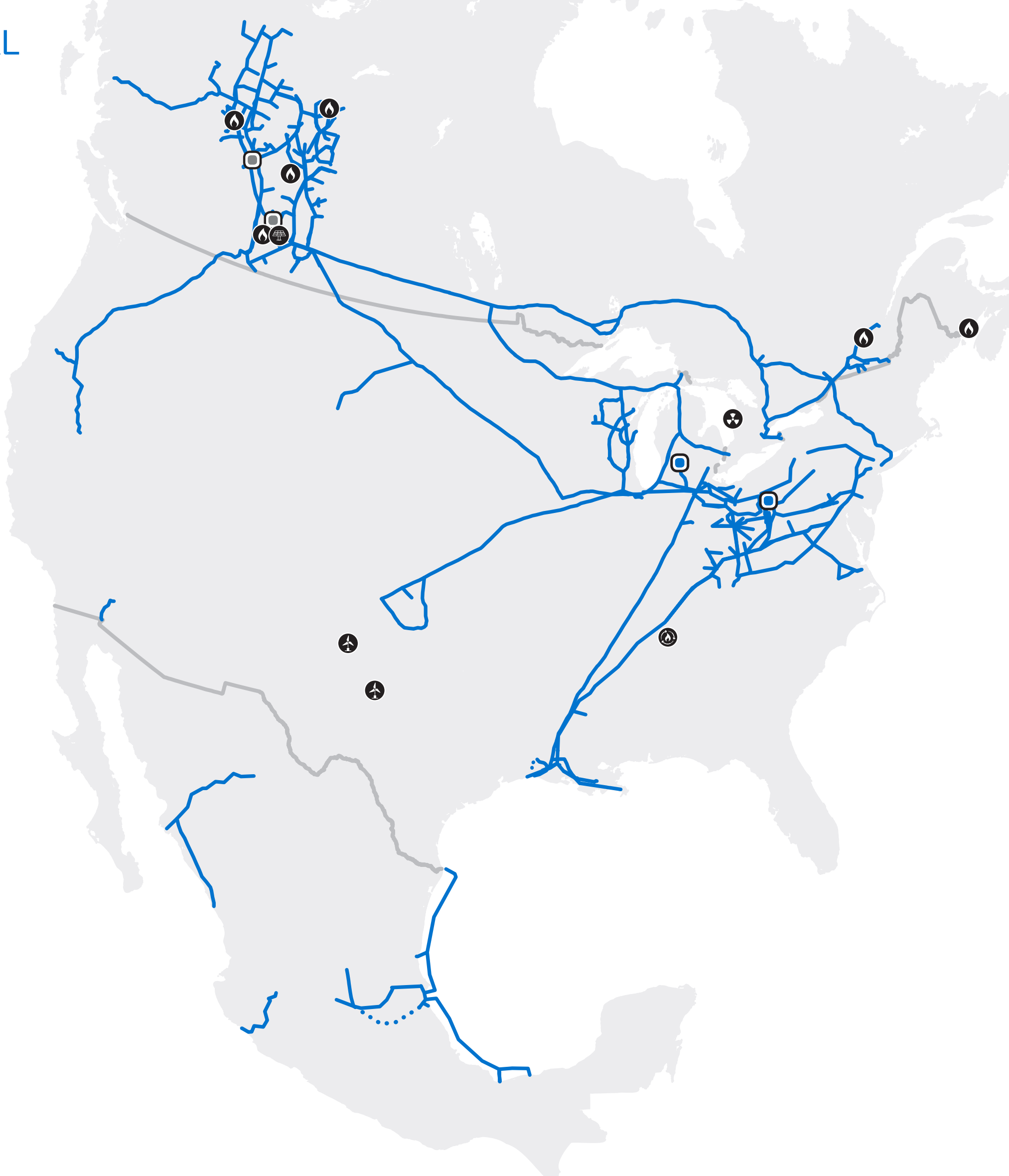
We are the only natural gas infrastructure company with critical assets in Canada, the U.S. and Mexico—connecting energy to opportunity across borders and continents.

UNWAVERING FOCUS ON NATURAL GAS

We are North America's leading natural gas transmission and storage company, positioned to meet rising demand from new power plant and data centre development, LNG exports, electrification and industrial growth.

COMPLEMENTARY POSITIONS IN POWER

Our stake in nuclear and expertise in gas-fired generation and storage position us to provide reliable energy supply and contribute to grid stability, while advancing lower-carbon solutions.



Management's discussion and analysis

February 12, 2026

This management's discussion and analysis (MD&A) contains information to help the reader make investment decisions about TC Energy Corporation (TC Energy). It discusses our business, operations, financial position, risks and other factors for the year ended December 31, 2025.

This MD&A should also be read in conjunction with our December 31, 2025 audited Consolidated financial statements and notes for the same period, which have been prepared in accordance with U.S. GAAP.

Contents

About this document

Throughout this MD&A, the terms we, us, our and TC Energy mean TC Energy Corporation and its subsidiaries. Abbreviations and acronyms that are not defined in the document are defined in the glossary on page 128. All information is as of February 12, 2026 and all amounts are in Canadian dollars, unless noted otherwise.

On October 1, 2024, TC Energy completed the spinoff of its Liquids Pipelines business into a new public company, South Bow Corporation (South Bow) (the Spinoff Transaction). Upon completion of the Spinoff Transaction, the Liquids Pipelines business was accounted for as a discontinued operation. To allow for a meaningful comparison, discussions throughout this MD&A are based on continuing operations unless otherwise noted. Refer to Note 4, Discontinued operations, of our 2025 Consolidated financial statements for additional information.

FORWARD-LOOKING INFORMATION

We disclose forward-looking information to help the reader understand management's assessment of our future plans and financial outlook and our future prospects overall.

Statements that are ***forward looking*** are based on certain assumptions and on what we know and expect today and generally include words like ***anticipate, expect, believe, may, will, should, estimate*** or other similar words.

Forward-looking statements in this MD&A include information about the following, among other things:

- our financial and operational performance, including the performance of our subsidiaries
- expectations about strategies and goals for growth and expansion, including acquisitions
- expected cash flows and future financing options available along with portfolio management
- expectations regarding the size, structure, timing, conditions and outcome of ongoing and future transactions
- expected dividend growth
- expected access to and cost of capital
- expected energy demand levels
- expected costs and schedules for planned projects, including projects under construction and in development
- expected capital expenditures, contractual obligations, commitments and contingent liabilities, including environmental remediation costs
- expected regulatory processes and outcomes
- expected outcomes with respect to legal proceedings, including arbitration and insurance claims
- expected impact of future tax and accounting changes
- commitments and targets contained in our Report on Sustainability, including statements related to our GHG emissions reduction targets, such as our methane emissions intensity target
- expected industry, market and economic conditions, and ongoing trade negotiations, including their impact on our customers and suppliers.

Forward-looking statements do not guarantee future performance. Actual events and results could be significantly different because of assumptions, risks or uncertainties related to our business or events that happen after the date of this MD&A.

Our forward-looking information is based on the following key assumptions and subject to the following risks and uncertainties:

Assumptions

- realization of expected impacts from acquisitions and divestitures
- regulatory decisions and outcomes
- planned and unplanned outages and the utilization of our pipelines, power and storage assets
- integrity and reliability of our assets
- anticipated construction costs, schedules and completion dates
- access to capital markets, including portfolio management
- expected industry, market and economic conditions, including the impact of these on our customers and suppliers
- inflation rates, commodity and labour prices
- interest, tax and foreign exchange rates
- nature and scope of hedging.

Risks and uncertainties

- realization of expected impacts from acquisitions and divestitures
- our ability to successfully implement our strategic priorities, and whether they will yield the expected benefits
- our ability to implement a capital allocation strategy aligned with maximizing shareholder value
- operating performance of our pipelines, power generation and storage assets
- amount of capacity sold and rates achieved in our pipeline businesses
- amount of capacity payments and revenues from power generation assets due to plant availability
- production levels within supply basins
- construction and completion of capital projects
- cost, availability of, and inflationary pressures on, labour, equipment and materials
- availability and market prices of commodities
- access to capital markets on competitive terms
- interest, tax and foreign exchange rates
- performance and credit risk of our counterparties
- regulatory decisions and outcomes of legal proceedings, including arbitration and insurance claims
- our ability to effectively anticipate and assess changes to government policies and regulations, including those related to the environment
- our ability to realize the value of tangible assets and contractual recoveries
- competition in the businesses in which we operate
- unexpected or unusual weather
- acts of civil disobedience
- cybersecurity and technological developments
- sustainability-related risks including climate-related risks and the impact of energy transition on our business
- economic and political conditions, and ongoing trade negotiations in North America, as well as globally
- global health crises, such as pandemics and epidemics, and the impacts related thereto.

You can read more about these factors and others in this MD&A and in other reports we have filed with Canadian securities regulators and the SEC.

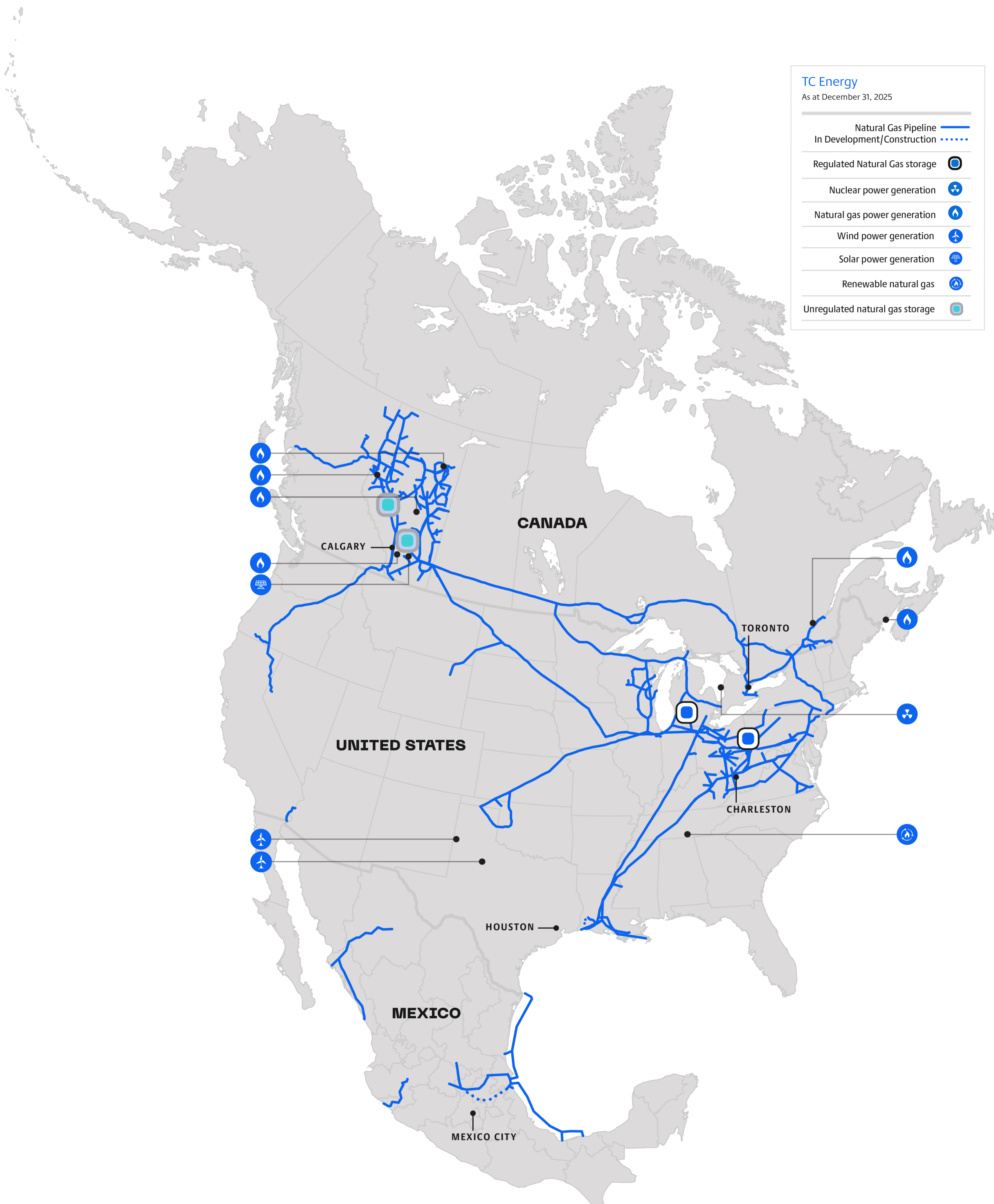
As actual results could vary significantly from the forward-looking information, you should not put undue reliance on forward-looking information and should not use future-oriented information or financial outlooks for anything other than their intended purpose. We do not update our forward-looking statements due to new information or future events unless we are required to by law.

FOR MORE INFORMATION

You can find more information about TC Energy in our Annual Information Form and other disclosure documents, which are available on SEDAR+ (www.sedarplus.ca).

About our business

With over 70 years of experience, TC Energy is a leader in the responsible development and reliable operation of North American energy infrastructure, including natural gas pipelines, power generation and natural gas storage facilities.



OUR CORE BUSINESSES

We operate in two core businesses – Natural Gas Pipelines and Power and Energy Solutions. In order to provide information that is aligned with how management decisions about our businesses are made and how performance of our businesses is assessed, our results are reflected in four operating segments: Canadian Natural Gas Pipelines, U.S. Natural Gas Pipelines, Mexico Natural Gas Pipelines and Power and Energy Solutions. We also have a Corporate segment consisting of corporate and administrative functions that provide governance, financing and other support to TC Energy's business segments.

TC Energy completed the Spinoff Transaction on October 1, 2024 and subsequently accounted for the Liquids Pipelines business as a discontinued operation. Refer to the Discontinued operations section on page 88 for additional information.

Year at-a-glance

at December 31 (millions of $)	2025	2024
Total assets by segment		
Canadian Natural Gas Pipelines	**31,371**	31,167
U.S. Natural Gas Pipelines	**56,617**	56,304
Mexico Natural Gas Pipelines	**16,342**	15,995
Power and Energy Solutions	**10,764**	10,217
Corporate	**3,460**	4,189
	118,554	117,872
Discontinued Operations	**197**	371
	118,751	118,243

year ended December 31 (millions of $)	2025	2024[1]
Total revenues from continuing operations by segment		
Canadian Natural Gas Pipelines	**5,785**	5,600
U.S. Natural Gas Pipelines	**7,145**	6,339
Mexico Natural Gas Pipelines	**1,450**	870
Power and Energy Solutions	**845**	954
Corporate	**14**	8
	15,239	13,771

1 Excludes revenues of $2,217 million related to discontinued operations, which represents nine months of Liquids Pipelines earnings in 2024.

year ended December 31 (millions of $)	2025	2024[1]
Comparable EBITDA from continuing operations by segment[2]		
Canadian Natural Gas Pipelines	**3,687**	3,388
U.S. Natural Gas Pipelines	**4,906**	4,511
Mexico Natural Gas Pipelines	**1,365**	999
Power and Energy Solutions	**1,008**	1,214
Corporate	**(14)**	(63)
	10,952	10,049

1 Excludes Comparable EBITDA from discontinued operations of $1,145 million, which represents nine months of Liquids Pipelines earnings in 2024.

2 Comparable EBITDA is a non-GAAP measure and does not have any standardized meaning as prescribed by U.S. GAAP and therefore may not be comparable to similar measures presented by other companies. The most directly comparable GAAP measure is segmented earnings (losses). Refer to the Financial results sections for each business segment for a reconciliation to comparable EBITDA as well as the About our business - Non-GAAP measures section for additional information.

OUR STRATEGY

Our vision is to be the trusted leader in North America's energy infrastructure, committed to excellence in safety, performance and stakeholder relationships. Our mission is to safely and efficiently move, generate and store the critical energy that North America and the world rely on. Our value proposition: to deliver solid growth with low risk and repeatable performance, year after year.

Our business consists of natural gas transportation and storage, as well as power generation assets:

- we deliver natural gas to Canada, the U.S. and Mexico, including to export terminals that ship LNG globally
- we generate electricity in Canada and the U.S., primarily from nuclear energy, but also from natural gas, wind and solar assets
- we store natural gas in Canada and the U.S. through regulated and non-regulated businesses.

These long-life infrastructure assets are anchored by our conservative risk preferences and are generally supported by long-term commercial arrangements and/or rate regulation. We believe that our assets will generate predictable and sustainable cash flows and earnings, providing the cornerstones of our low-risk value proposition. Our long-term strategy is driven by the following key beliefs:

- natural gas will continue to play a pivotal role in North America's energy future and support global GHG emissions reduction
- the need for reliable, on-demand energy sources will continue to grow
- energy assets will become increasingly valuable in a world with growing energy demand and existing challenges in developing new infrastructure.

Allocation of comparable EBITDA from continuing operations[1]

year ended December 31	2025	2024
Comparable EBITDA from continuing operations by segment[2]		
Canadian Natural Gas Pipelines	**34%**	33%
U.S. Natural Gas Pipelines	**45%**	45%
Mexico Natural Gas Pipelines	**12%**	10%
Power and Energy Solutions	**9%**	12%
	100%	100%

1 Refer to the Financial highlights section for an allocation of segmented earnings by business segment.
2 Excludes losses from Corporate comparable EBITDA from continuing operations of $14 million and $63 million for the years ended December 31, 2025 and 2024, respectively.

Our asset mix will continue to evolve with the North American energy mix. We anticipate the following trends in capital allocation over the next several years:

- Natural Gas Pipelines will continue to attract capital to meet growing customer demand, driven by coal-to-gas conversion, LNG exports and data centre buildouts
- Power and Energy Solutions' capital will primarily be allocated to extending the life and increasing the capacity of the nuclear business. We will make measured investment in emerging technologies to develop capabilities that are complementary to our Natural Gas Pipelines business, without taking significant commodity price risk, volumetric risk or utilizing unproven technologies
- additional discretionary investment will fund select high-grade opportunities in our development projects portfolio and incremental opportunities around existing assets across our businesses.

Key components of our strategy

Maximize the value of our assets through safety and operational excellence

Maintaining safe and reliable operations by maximizing asset availability and integrity while minimizing environmental impacts remains the foundation of our business. Our extensive natural gas pipeline network connects long-life, low-cost supply basins with premium North American and export markets, generating predictable and sustainable cash flows and earnings, while our power and non-regulated storage assets, primarily under long-term contracts, provide stable returns. We continually seek to enhance and protect asset value through operational, commercial and marketing initiatives.

Execute our selective portfolio of growth projects

Safety, executability, profitability, and reliability are fundamental to our investments, which focus on developing high-quality, long-life assets largely underpinned by long-term contracts or rate regulation. Leveraging our incumbent positions in regions with growing natural gas and power demand, we manage costs and construction risk in a disciplined manner to maximize capital efficiency and shareholder returns. We also look to advance select lower-carbon growth initiatives in emerging sub-sectors where technology is proven, risks and returns are acceptable and we can build a strong competitive position.

Ensure financial strength and agility

Disciplined capital allocation supports our ability to maximize asset value over the short, medium and long term while improving cost competitiveness, extending asset life and remaining within annual net capital spend targets. We assess opportunities to develop or acquire complementary energy infrastructure that protects and grows our business, enhances resilience under a changing energy mix and diversifies access to attractive supply and market regions within our risk preferences. Supported by our high-quality, diversified portfolio and core competencies in safety, operational excellence, and project execution, we aim to deliver predictable, low-risk cash flows and shareholder value across various economic cycles and energy transition scenarios.

Our risk preferences

The following is an overview of our risk philosophy:

- **financial strength and flexibility:** rely on internally generated cash flows, existing debt capacity, partnerships and portfolio management to finance new initiatives
- **known and acceptable project risks:** select investments with known, acceptable and manageable project execution risk, including stakeholder considerations, partnership agreements, human capital and capability constraints
- **business underpinned by strong fundamentals and policy support:** invest in assets with stable cash flows supported by strong underlying macroeconomic fundamentals, conducive policy and regulations and/or long-term contracts with creditworthy counterparties
- **manage credit metrics to ensure strong investment-grade ratings:** investment-grade ratings are an important competitive advantage and we manage leverage to ensure that strong access to capital on competitive terms is maintained while balancing the interests of equity and fixed income investors
- **prudent management of counterparty exposure:** limit counterparty concentration and sovereign risk; seek diversification and solid commercial arrangements underpinned by strong fundamentals.

2025 FINANCIAL HIGHLIGHTS

We use certain financial measures that do not have a standardized meaning under GAAP because we believe they improve our ability to compare results between reporting periods and enhance understanding of our operating performance. Known as non-GAAP measures, they may not be comparable to similar measures provided by other companies.

Comparable EBITDA, comparable earnings and comparable earnings per common share from continuing and discontinued operations and comparable funds generated from operations are all non-GAAP measures. Refer to page 22 for more information about the non-GAAP measures we use, as well as the Financial results section in each business segment and Discontinued operations section for reconciliations to the most directly comparable GAAP measures.

As discussed on page 10 of the About this document section, TC Energy completed the Spinoff Transaction on October 1, 2024. To allow for a meaningful comparison, discussions throughout this MD&A are based on continuing operations unless otherwise noted. Refer to the Discontinued operations section for additional information.

year ended December 31 (millions of $, except per share amounts)	**2025**	**2024**	**2023**
Income			
Revenues	**15,239**	13,771	13,267
Net income (loss) attributable to common shares	**3,400**	4,594	2,829
from continuing operations	3,612	4,199	2,217
from discontinued operations[1]	(212)	395	612
Net income (loss) per common share – basic	**$3.27**	$4.43	$2.75
from continuing operations	$3.47	$4.05	$2.15
from discontinued operations[1]	($0.20)	$0.38	$0.60
Comparable EBITDA[2]	**10,952**	11,194	10,988
from continuing operations	10,952	10,049	9,472
from discontinued operations[1]	—	1,145	1,516
Comparable earnings[2]	**3,654**	4,430	4,652
from continuing operations	3,654	3,865	3,896
from discontinued operations[1]	—	565	756
Comparable earnings per common share[2]	**$3.51**	$4.27	$4.52
from continuing operations	$3.51	$3.73	$3.78
from discontinued operations[1]	—	$0.54	$0.74

1 Represents nine months of Liquids Pipelines earnings in 2024 and a full year of earnings in 2023. Refer to the Discontinued operations section for additional information.

2 Additional information on the most directly comparable GAAP measure can be found on page 22.

year ended December 31 (millions of $)	2025	2024	2023
Cash flows[1]			
Net cash provided by operations[2]	**7,346**	7,696	7,268
Comparable funds generated from operations[2,3]	**7,996**	7,890	7,980
Capital spending[4]	**6,337**	7,904	12,298
Acquisitions, net of cash acquired	**—**	—	(307)
Proceeds from sales of assets, net of transaction costs	**—**	791	33
Disposition of equity interest, net of transaction costs[5]	**—**	419	5,328

1 Includes continuing and discontinued operations.
2 Includes nine months of Liquids Pipelines earnings in 2024 and a full year of earnings in 2023. Refer to the Discontinued operations section for additional information.
3 Additional information on the most directly comparable GAAP measure can be found on page 22.
4 Capital spending reflects cash flows associated with our Capital expenditures, Capital projects in development and Contributions to equity investments. For the year ended December 31, 2024, Contributions to equity investments was net of Other distributions from equity investments of $3.1 billion in the Canadian Natural Gas Pipelines segment. Refer to Note 5, Segmented information, Note 10, Equity investments and Note 11, Loans with affiliates, of our 2025 Consolidated financial statements for additional information.
5 Included in the Financing activities section of the Consolidated statement of cash flows, of our 2025 Consolidated financial statements.

at December 31 (millions of $, except per share amounts)	2025	2024	2023
Balance sheet			
Total assets[1]	**118,751**	118,243	125,034
Long-term debt, including current portion	**46,792**	47,931	52,914
Junior subordinated notes	**12,094**	11,048	10,287
Preferred shares	**2,255**	2,499	2,499
Non-controlling interests	**9,604**	10,768	9,455
Common shareholders' equity	**25,040**	25,093	27,054
Dividends declared[2]			
per common share[3]	**$3.40**	$3.7025	$3.72
Basic common shares (millions)			
– weighted average for the year ended	**1,040**	1,038	1,030
– issued and outstanding at end of year	**1,041**	1,039	1,037

1 At December 31, 2025, includes assets of $197 million (2024 - $371 million; 2023 - $15,510 million), related to discontinued operations. Refer to Note 4, Discontinued operations, of our 2025 Consolidated financial statements for additional information.
2 For the year ended.
3 Dividends declared in fourth quarter 2024 and thereafter reflect TC Energy's proportionate allocation following the Spinoff Transaction.

Consolidated results

year ended December 31 (millions of $, except per share amounts)	2025	2024	2023
Canadian Natural Gas Pipelines	**2,164**	2,016	(90)
U.S. Natural Gas Pipelines	**3,927**	4,053	3,531
Mexico Natural Gas Pipelines	**1,186**	929	796
Power and Energy Solutions	**773**	1,102	1,004
Corporate	**(14)**	(136)	(144)
Total segmented earnings (losses)	**8,036**	7,964	5,097
Interest expense	**(3,407)**	(3,019)	(2,966)
Allowance for funds used during construction	**453**	784	575
Foreign exchange gains (losses), net	**157**	(147)	320
Interest income and other	**205**	324	272
Income (loss) from continuing operations before income taxes	**5,444**	5,906	3,298
Income tax (expense) recovery from continuing operations	**(1,138)**	(922)	(842)
Net income (loss) from continuing operations	**4,306**	4,984	2,456
Net income (loss) from discontinued operations, net of tax[1]	**(212)**	395	612
Net income (loss)	**4,094**	5,379	3,068
Net (income) loss attributable to non-controlling interests	**(575)**	(681)	(146)
Net income (loss) attributable to controlling interests	**3,519**	4,698	2,922
Preferred share dividends	**(119)**	(104)	(93)
Net income (loss) attributable to common shares	**3,400**	4,594	2,829
Net income (loss) per common share – basic	**$3.27**	$4.43	$2.75
from continuing operations	**$3.47**	$4.05	$2.15
from discontinued operations[1]	**($0.20)**	$0.38	$0.60

1 Represents nine months of Liquids Pipelines earnings in 2024 and a full year of earnings in 2023. Refer to the Discontinued operations section for additional information.

year ended December 31 (millions of $)	2025	2024	2023
Amounts attributable to common shares			
Net income (loss) from continuing operations	**4,306**	4,984	2,456
Net (income) loss attributable to non-controlling interests	**(575)**	(681)	(146)
Net income (loss) attributable to controlling interests from continuing operations	**3,731**	4,303	2,310
Preferred share dividends	**(119)**	(104)	(93)
Net income (loss) attributable to common shares from continuing operations	**3,612**	4,199	2,217
Net income (loss) from discontinued operations, net of tax[1]	**(212)**	395	612
Net income (loss) attributable to common shares	**3,400**	4,594	2,829

1 Represents nine months of Liquids Pipelines earnings in 2024 and a full year of earnings in 2023. Refer to the Discontinued operations section for additional information.

Net income attributable to common shares from continuing operations in 2025 was $3.6 billion or $3.47 per common share (2024 – $4.2 billion or $4.05 per common share; 2023 – $2.2 billion or $2.15 per common share), a decrease of $0.6 billion or $0.58 per common share in 2025 compared to 2024 and an increase of $2.0 billion or $1.90 per common share in 2024 compared to 2023. Refer to the About our business - Non-GAAP measures section for a listing of specific items included in Net income attributable to common shares from continuing operations, which have been excluded from our calculation of comparable measures.

Refer to the Discontinued operations - Non-GAAP measures section for a listing of specific items included in Net income (loss) from discontinued operations, net of tax, which have been excluded from our calculation of comparable measures.

Cash flows

Net cash provided by operations of $7.3 billion in 2025 was five per cent lower than 2024 primarily due to the timing of working capital changes, partially offset by higher funds generated from operations. Comparable funds generated from operations of $8.0 billion in 2025 were one per cent higher than 2024 primarily due to higher comparable EBITDA and risk management activities used to manage our foreign exchange exposure to net liabilities in Mexico and to U.S. dollar-denominated income, partially offset by lower distributions from our equity investments.

Funds used in investing activities

Capital spending[1]

year ended December 31			
(millions of $)	**2025**	**2024**	**2023**
Canadian Natural Gas Pipelines	**1,405**	2,100	6,184
U.S. Natural Gas Pipelines	**3,457**	2,575	2,660
Mexico Natural Gas Pipelines	**522**	2,228	2,292
Power and Energy Solutions	**922**	824	1,080
Corporate	**31**	50	33
	6,337	7,777	12,249
Discontinued operations	**—**	127	49
	6,337	7,904	12,298

1 Capital spending reflects cash flows associated with our Capital expenditures, Capital projects in development and Contributions to equity investments. For the year ended December 31, 2024, Contributions to equity investments were net of Other distributions from equity investments of $3.1 billion in the Canadian Natural Gas Pipelines segment. Refer to Note 5, Segmented information, Note 10, Equity investments and Note 11, Loans with affiliates, of our 2025 Consolidated financial statements for additional information.

In 2025 and 2024, we invested $6.3 billion and $7.9 billion, respectively, in capital projects to maintain and optimize the value of our existing assets and to develop new, complementary assets in high-demand areas. Our total capital spending in 2025 and 2024 included contributions of $1.1 billion and $1.5 billion (net of distributions), respectively, to our equity investments, predominantly related to Bruce Power and Coastal GasLink Limited Partnership (Coastal GasLink LP).

Proceeds from sales of assets

In 2024, TC Energy and its partner, Northern New England Investment Company, Inc., a subsidiary of Énergir L.P. (Énergir), completed the sale of Portland Natural Gas Transmission System (PNGTS) to a third party. Our share of the proceeds was $743 million (US$546 million), net of transaction costs.

In 2024, we also completed the sale of other non-core assets for gross proceeds of $48 million.

In 2023, we completed the sale of a 20.1 per cent equity interest in Port Neches Link LLC to its joint venture partner, Motiva Enterprises, for gross proceeds of $33 million (US$25 million). As part of the Spinoff Transaction on October 1, 2024, our remaining interest in Port Neches Link LLC was transferred to South Bow.

Acquisitions

In 2023, we acquired 100 per cent of the Class B Membership Interests in Fluvanna Wind Farm and Blue Cloud Wind Farm (Texas Wind Farms) for US$224 million, before post-closing adjustments.

Balance sheet

We continue to maintain a solid financial position while growing our total assets, excluding discontinued operations, by $0.7 billion in 2025. At December 31, 2025, common shareholders' equity and non-controlling interests represented 36 per cent (2024 – 37 per cent) of our capital structure, while other subordinated capital, in the form of junior subordinated notes and preferred shares, represented an additional 14 per cent (2024 – 14 per cent). Refer to the Financial condition section for additional information.

Dividends

Commencing with the dividends payable on January 31, 2025 to shareholders of record at the close of business on December 31, 2024, the amounts reflect TC Energy's proportionate allocation following the Spinoff Transaction. Refer to our 2024 Annual Report for additional information.

Our Board of Directors have declared a quarterly dividend on our outstanding common shares of $0.8775 per common share for the quarter ending March 31, 2026, which equates to an annual dividend of $3.51 per common share.

Dividend reinvestment and share purchase plan

Under the DRP, eligible holders of common and preferred shares of TC Energy can reinvest their dividends and make optional cash payments to obtain additional TC Energy common shares. From August 31, 2022 to July 31, 2023, common shares were issued from treasury at a discount of two per cent to market prices over a specified period.

Commencing with the dividends declared on July 27, 2023, common shares purchased under TC Energy's DRP are acquired on the open market at 100 per cent of the weighted average purchase price.

Cash dividends paid

year ended December 31 (millions of $)	**2025**	**2024**	**2023**
Common shares	**3,507**	3,953	2,787
Preferred shares	**114**	99	92

NON-GAAP MEASURES

This MD&A references non-GAAP measures, which are identified in the table below. These measures do not have any standardized meaning as prescribed by GAAP and therefore may not be comparable to similar measures presented by other entities. These measures are reviewed regularly by our President and Chief Executive Officer, management and the Board of Directors in assessing our performance and making decisions regarding the ongoing operations of our business and its ability to generate cash flows. Some or all of these measures may also be used by investors and other external users of our financial statements as a supplemental measure to provide decision-useful information regarding our period-over-period performance and ability to generate earnings that are core to our ongoing operations. Discussions throughout this MD&A on the factors impacting comparable earnings before interest, taxes, depreciation and amortization (comparable EBITDA) and comparable earnings before interest and taxes (comparable EBIT) are consistent with the factors that impact segmented earnings, except where noted otherwise.

Comparable measures

We calculate comparable measures by adjusting certain GAAP measures for specific items we believe are significant but not reflective of our underlying operations in the period. Except as otherwise described herein, these comparable measures are calculated on a consistent basis from period to period and are adjusted for specific items in each period, as applicable.

Our decision to adjust for a specific item in reporting comparable measures is subjective and made after careful consideration. We maintain a consistent approach to adjustments, which generally fall into the categories described below:

- by their nature are unusual, infrequent and separately identifiable from our normal business operations and in our view are not reflective of our underlying operations in the period and generally include the following:
  - gains or losses on sales of assets or assets held for sale; impairment of goodwill, plant, property and equipment, equity investments and other assets; legal, contractual and other infrequent settlements; acquisition, integration and restructuring costs; expected credit loss provisions on net investment in leases and certain contract assets in Mexico; impacts resulting from changes in legislation and enacted tax rates and unusual tax refunds/payments and valuation allowance adjustments
- unrealized gains and losses related to fair value adjustments that do not reflect realized earnings or losses or cash impacts incurred in the current period from our underlying operations and generally include the following:
  - unrealized gains and losses from changes in the fair value of derivatives related to financial and commodity price risk management activities; unrealized fair value adjustments related to our proportionate share of Bruce Power's risk management activities and its funds invested for post-retirement benefits; unrealized foreign exchange gains and losses on intercompany loans that impact consolidated earnings.

The following table identifies our non-GAAP measures against their most directly comparable GAAP measures. These measures are applicable to our continuing and discontinued operations. Quantitative reconciliations of our comparable measures to their GAAP measures and a discussion of specific adjustments made for 2025 and comparative periods can be found on pages 24 and 25, the Financial results section in each business segment, and the Financial condition section. Non-GAAP measures for discontinued operations are found in the Discontinued operations section on page 89.

Non-GAAP measure	GAAP measure
comparable EBITDA	segmented earnings (losses)
comparable EBIT	segmented earnings (losses)
comparable earnings	net income (loss) attributable to common shares
comparable earnings per common share	net income (loss) per common share
funds generated from operations	net cash provided by operations
comparable funds generated from operations	net cash provided by operations

Comparable EBITDA and comparable EBIT

Comparable EBITDA represents segmented earnings (losses) adjusted for specific items described in the Comparable measures section, excluding charges for depreciation and amortization. We use comparable EBITDA as a measure of our earnings from ongoing operations as it is a useful indicator of our performance and is also presented on a consolidated basis. Comparable EBIT represents segmented earnings (losses) adjusted for specific items and is an effective tool for evaluating trends in each segment. Refer to each business segment and the Discontinued operations section for a reconciliation to segmented earnings (losses).

Funds generated from operations and comparable funds generated from operations

Funds generated from operations reflects net cash provided by operations before changes in operating working capital. The components of changes in working capital are disclosed in Note 28, Changes in operating working capital, of our 2025 Consolidated financial statements. Comparable funds generated from operations is adjusted for the cash impact of specific items described in the Comparable measures section. We believe funds generated from operations and comparable funds generated from operations are useful measures of our consolidated operating cash flows because they exclude fluctuations from working capital balances, which do not necessarily reflect underlying operations in the same period, and are used to provide a consistent measure of the cash-generating ability of our businesses. Refer to the Financial condition section for a reconciliation to Net cash provided by operations.

Comparable earnings and comparable earnings per common share

Comparable earnings represents earnings attributable to common shareholders on a consolidated basis, adjusted for specific items described in the Comparable measures section. Comparable earnings is comprised of segmented earnings (losses), Interest expense, AFUDC, Foreign exchange (gains) losses, net, Interest income and other, Income tax expense (recovery), Net income (loss) attributable to non-controlling interests and Preferred share dividends on our Consolidated statement of income, adjusted for specific items. We use comparable earnings as a measure of our earnings from ongoing operations as it is a useful indicator of our performance and is also presented on a consolidated basis. Refer to page 25 and the Discontinued operations section for reconciliations to Net income (loss) attributable to common shares and Net income (loss) per common share for our continuing operations and discontinued operations.

Comparable earnings and comparable earnings per common share - from continuing operations

The following specific items were recognized in Net income (loss) attributable to common shares from continuing operations and were excluded from comparable earnings from continuing operations:

2025

- a pre-tax impairment charge of $110 million for certain Power and Energy Solutions projects following our decision to discontinue development along with updated forecast assumptions as we refocus our Power and Energy Solutions strategy
- pre-tax unrealized foreign exchange losses, net, of $89 million on the peso-denominated intercompany loan between TransCanada PipeLines Limited (TCPL) and Transportadora de Gas Natural de la Huasteca (TGNH), net of non-controlling interest
- a pre-tax expense of $75 million on the expected credit loss provision related to TGNH net investment in leases, net of non-controlling interest as well as certain contract assets in Mexico.

2024

- a pre-tax gain of $572 million related to the sale of PNGTS which was completed on August 15, 2024
- a pre-tax net gain on debt extinguishment of $228 million related to the purchase and cancellation of certain senior unsecured notes and medium term notes and the retirement of outstanding callable notes in October 2024
- pre-tax unrealized foreign exchange gains, net, of $143 million on the peso-denominated intercompany loan between TCPL and TGNH, net of non-controlling interest
- a pre-tax gain of $48 million related to the sale of non-core assets in U.S. Natural Gas Pipelines and Canadian Natural Gas Pipelines
- a pre-tax recovery of $22 million on the expected credit loss provision related to TGNH net investment in leases, net of non-controlling interest as well as certain contract assets in Mexico
- a deferred income tax expense of $96 million resulting from the revaluation of remaining deferred tax balances following the Spinoff Transaction
- a pre-tax impairment charge of $36 million for a Power and Energy Solutions project following our decision to discontinue development as we refocus our Power and Energy Solutions strategy
- a pre-tax expense of $34 million related to a non-recurring third-party settlement
- a pre-tax expense of $24 million related to Focus Project costs
- pre-tax costs of $10 million related to the NGTL System ownership transfer.

2023

- a pre-tax impairment charge of $2.1 billion related to our equity investment in Coastal GasLink LP
- a pre-tax expense of $65 million related to Focus Project costs
- pre-tax unrealized foreign exchange losses, net, of $44 million on the peso-denominated intercompany loan between TCPL and TGNH
- a pre-tax recovery of $80 million on the expected credit loss provision related to TGNH net investment in leases and certain contract assets in Mexico.

Refer to the Financial results section in each business segment and the Financial condition section of this MD&A for additional information.

Reconciliation of net income (loss) attributable to common shares to comparable earnings - from continuing operations

year ended December 31 (millions of $, except per share amounts)	2025	2024	2023
Net income (loss) attributable to common shares from continuing operations	**3,612**	4,199	2,217
Specific items (pre tax):			
Power and Energy Solutions impairment charges	**110**	36	—
Foreign exchange (gains) losses, net – intercompany loan[1]	**89**	(143)	44
Expected credit loss provision on net investment in leases and certain contract assets in Mexico[2]	**75**	(22)	(80)
Gain on sale of PNGTS	**—**	(572)	—
Net gain on debt extinguishment[3]	**—**	(228)	—
Gain on sale of non-core assets	**—**	(48)	—
Third-party settlement	**—**	34	—
Focus Project costs[4]	**—**	24	65
NGTL System ownership transfer costs	**—**	10	—
Coastal GasLink impairment charge	**—**	—	2,100
Bruce Power unrealized fair value adjustments	**(30)**	(8)	(7)
Risk management activities[5]	**(228)**	433	(395)
Taxes on specific items[6]	**26**	150	(48)
Comparable earnings from continuing operations	**3,654**	3,865	3,896
Net income (loss) per common share from continuing operations	**$3.47**	$4.05	$2.15
Specific items (net of tax)	**0.04**	(0.32)	1.63
Comparable earnings per common share from continuing operations	**$3.51**	$3.73	$3.78

1 In 2023, TCPL and TGNH entered into an unsecured revolving credit facility. While the loan receivable and payable eliminate on consolidation, differences in each entity's reporting currency create a net income impact from revaluing and translating these balances into TC Energy's reporting currency. As the resulting unrealized foreign exchange gains and losses do not reflect amounts expected to be realized at settlement, we exclude them from comparable measures, net of non-controlling interest.

2 We have recognized an expected credit loss provision related to net investment in leases and certain contract assets in Mexico, which will fluctuate from period to period based on changing economic assumptions and forward-looking information. This provision is an estimate of losses that may occur over the duration of the TSA through 2055. This provision does not reflect losses or cash outflows that were incurred under this lease arrangement in the current period or from our underlying operations, and therefore, we have excluded any unrealized changes, net of non-controlling interest, from comparable measures. Refer to Note 27, Risk management and financial instruments, of our 2025 Consolidated financial statements for additional information.

3 In October 2024, TCPL commenced and completed our cash tender offers to purchase and cancel certain senior unsecured notes and medium term notes at a 7.73 per cent weighted average discount. In addition, we retired outstanding callable notes at par. These extinguishments of debt resulted in a pre-tax net gain of $228 million, primarily due to fair value discounts and unamortized debt issue costs. The net gain on debt extinguishment was recorded in Interest expense in the Consolidated statement of income. Refer to Note 19, Long-term debt, of our 2025 Consolidated financial statements for additional information.

4 In 2023 and 2024, we recognized expenses related to the Focus Project for external consulting and severance, some of which are not recoverable through regulatory and commercial tolling structures.

5

year ended December 31 (millions of $)	2025	2024	2023
U.S. Natural Gas Pipelines	**58**	(113)	80
Canadian Power	**(16)**	84	(31)
U.S. Power	**9**	(10)	9
Natural Gas Storage	**(35)**	(57)	91
Interest rate	**2**	(71)	—
Foreign exchange	**210**	(266)	246
	228	(433)	395
Income tax attributable to risk management activities	**(56)**	105	(99)
Total unrealized gains (losses) from risk management activities	**172**	(328)	296

6 Refer to the Corporate - Financial results section for additional information.

Comparable EBITDA to comparable earnings - from continuing operations

Comparable EBITDA from continuing operations represents segmented earnings (losses) from continuing operations adjusted for the specific items described above and excludes charges for depreciation and amortization. For further information on our reconciliation to comparable EBITDA, refer to the Financial results sections for each business segment.

year ended December 31 (millions of $, except per share amounts)	2025	2024	2023
Comparable EBITDA from continuing operations			
Canadian Natural Gas Pipelines	**3,687**	3,388	3,335
U.S. Natural Gas Pipelines	**4,906**	4,511	4,385
Mexico Natural Gas Pipelines	**1,365**	999	805
Power and Energy Solutions	**1,008**	1,214	1,020
Corporate	**(14)**	(63)	(73)
Comparable EBITDA from continuing operations	**10,952**	10,049	9,472
Depreciation and amortization	**(2,769)**	(2,535)	(2,446)
Interest expense included in comparable earnings	**(3,409)**	(3,176)	(2,966)
Allowance for funds used during construction	**453**	784	575
Foreign exchange gains (losses), net included in comparable earnings	**96**	(85)	118
Interest income and other	**205**	324	272
Income tax (expense) recovery included in comparable earnings	**(1,112)**	(772)	(890)
Net (income) loss attributable to non-controlling interests included in comparable earnings	**(643)**	(620)	(146)
Preferred share dividends	**(119)**	(104)	(93)
Comparable earnings from continuing operations	**3,654**	3,865	3,896
Comparable earnings per common share from continuing operations	**$3.51**	$3.73	$3.78

Comparable EBITDA from continuing operations

2025 versus 2024

Comparable EBITDA from continuing operations in 2025 increased by $903 million compared to 2024 primarily due to the net result of the following:

- increased EBITDA from Canadian Natural Gas Pipelines primarily due to higher flow-through costs and incentive earnings on the NGTL System and Mainline and higher contributions from Coastal GasLink mainly resulting from the declared commercial in-service of the pipeline in fourth quarter 2024
- higher U.S. dollar-denominated EBITDA from Mexico Natural Gas Pipelines mainly due to higher earnings in TGNH primarily related to the completion of the Southeast Gateway pipeline in second quarter 2025, partially offset by lower equity earnings from Sur de Texas as a result of peso-denominated financial exposure and higher income tax expense mainly related to foreign exchange impacts of U.S dollar-denominated liabilities
- higher U.S. dollar-denominated EBITDA from U.S. Natural Gas Pipelines due to an increase in earnings from Columbia Gas as a result of higher transportation rates effective April 1, 2025, incremental earnings from projects placed in service and additional contract sales, partially offset by lower earnings from our equity investments and higher operational costs
- increased EBITDA from Corporate primarily due to costs in 2024 related to TC Energy's corporate services and governance functions that were not allocated to discontinued operations
- decreased Power and Energy Solutions EBITDA resulting from lower contributions from Bruce Power mainly due to the Unit 4 Major Component Replacement (MCR), higher operating costs, partially offset by a higher contract price; decreased Canadian Power earnings primarily due to lower realized power prices, partially offset by Natural Gas Storage and other contributions reflecting the net impact of lower business development costs and lower realized Alberta natural gas storage spreads
- the positive foreign exchange impact of a stronger U.S. dollar on the Canadian dollar equivalent comparable EBITDA in our U.S. dollar-denominated operations. As detailed on page 72, U.S. dollar-denominated comparable EBITDA from continuing operations increased by US$463 million compared to 2024, which was translated to Canadian dollars at an average rate of 1.40 in 2025 versus 1.37 in 2024. Refer to the Foreign exchange section for additional information.

2024 versus 2023

Comparable EBITDA from continuing operations in 2024 increased by $577 million compared to 2023 primarily due to the net result of the following:

- increased Power and Energy Solutions EBITDA primarily attributable to higher contributions from Bruce Power due to higher generation and a higher contract price, and Natural Gas Storage and other due to higher realized Alberta natural gas storage spreads, partially offset by decreased Canadian Power earnings primarily due to lower realized power prices net of lower natural gas fuel costs
- higher U.S. dollar-denominated EBITDA from Mexico Natural Gas Pipelines mainly due to increased equity earnings from Sur de Texas as a result of peso-denominated financial exposure and lower income tax expense
- increased EBITDA from Canadian Natural Gas Pipelines primarily due to higher flow-through costs and increased rate-base earnings on the NGTL System and Foothills, partially offset by lower earnings from Coastal GasLink related to the recognition of a $200 million incentive payment in 2023
- higher U.S. dollar-denominated EBITDA from U.S. Natural Gas Pipelines due to incremental earnings from growth projects placed in service and additional contract sales, partially offset by higher operational costs and decreased earnings as a result of the sale of PNGTS, which was completed on August 15, 2024
- the positive foreign exchange impact of a stronger U.S. dollar on the Canadian dollar equivalent comparable EBITDA in our U.S. dollar-denominated operations. As detailed on page 72,U.S. dollar-denominated comparable EBITDA from continuing operations increased by US$180 million compared to 2023, which was translated to Canadian dollars at an average rate of 1.37 in 2024 versus 1.35 in 2023. Refer to the Foreign exchange section for additional information.

Due to the flow-through treatment of certain costs including income taxes, financial charges and depreciation in our Canadian rate-regulated pipelines, changes in these costs impact our comparable EBITDA despite having no significant effect on net income.

Comparable earnings from continuing operations

2025 versus 2024

Comparable earnings from continuing operations in 2025 were $211 million or $0.22 per common share lower than in 2024, and were primarily the net result of:

- changes in comparable EBITDA from continuing operations described above
- higher income tax expense primarily due to Mexico foreign exchange exposure and higher flow-through income taxes
- lower AFUDC primarily due to the completion of the Southeast Gateway pipeline project
- higher depreciation and amortization primarily due to higher depreciation rates on the NGTL System under the 2025-2029 NGTL Settlement and depreciation rate changes as a result of the Columbia Gas Settlement
- higher interest expense primarily due to lower capitalized interest resulting from the declared commercial in-service of the Coastal GasLink pipeline in fourth quarter 2024 and increased levels of short-term borrowing
- lower interest income and other due to lower interest earned on short-term investments and an increase in insurance-related provisions
- higher net income attributable to non-controlling interests primarily due to the net effect of higher net income recognized from Columbia Gas Transmission, LLC (Columbia Gas) and Columbia Gulf Transmission, LLC (Columbia Gulf) assets, the completion of the Southeast Gateway pipeline in second quarter 2025 and the full year impact of the sale of a 13.01 per cent non-controlling equity interest in TGNH to the CFE, completed in second quarter 2024
- risk management activities used to manage our foreign exchange exposure to net liabilities in Mexico and to U.S. dollar-denominated income and the revaluation of our peso-denominated net monetary liabilities to U.S. dollars.

2024 versus 2023

Comparable earnings from continuing operations in 2024 were $31 million or $0.05 per common share lower than in 2023, and were primarily the net result of:

- changes in comparable EBITDA from continuing operations described above
- higher depreciation and amortization reflecting expansion facilities and new projects placed in service
- higher interest expense primarily due to long-term debt issuances, net of maturities, the foreign exchange impact of a stronger U.S. dollar in 2024 compared to 2023, higher interest rates on short-term borrowings in 2024 and the impact of interest expense allocated to discontinued operations for nine months in 2024 compared to a full year in 2023
- higher AFUDC predominantly due to spending on the Southeast Gateway pipeline project, partially offset by projects placed in service and the cessation of AFUDC on Tula in fourth quarter 2023
- risk management activities used to manage our foreign exchange exposure to net liabilities in Mexico and to U.S. dollar-denominated income and the revaluation of our peso-denominated net monetary liabilities to U.S. dollars
- higher interest income and other due to higher interest earned on short-term investments and a reduction in insurance-related provisions
- decreased income tax expense due to the impact of Mexico foreign exchange exposure and lower comparable earnings subject to income tax, partially offset by lower foreign income tax rate differentials and higher flow-through income taxes
- higher net income attributable to non-controlling interests primarily due to the net effect of the sale of a 40 per cent non-controlling equity interest in Columbia Gas and Columbia Gulf in fourth quarter 2023 and the full year impact of the 13.01 per cent non-controlling equity interest in TGNH to the CFE, completed in second quarter 2024, partially offset by the divestiture of PNGTS in third quarter 2024.

Comparable earnings per common share reflect the dilutive effect of common shares issued. Refer to the Financial condition section for additional information.

SUPPLEMENTARY FINANCIAL MEASURE

Net capital expenditures

Net capital expenditures represents capital costs incurred for growth projects, maintenance capital expenditures, contributions to equity investments and projects under development, adjusted for the portion attributed to non-controlling interests in the entities we control. Net capital expenditures reflect capital costs incurred during the period, excluding the impact of timing of cash payments. We use net capital expenditures as a key measure in evaluating our performance in managing our capital spending activities in comparison to our capital plan.

Net capital expenditures does not include an adjustment related to the CFE's minority interest in TGNH capital expenditures until after the in-service of the projects included as part of the 2022 strategic alliance between TGNH and the CFE. The CFE's contribution in second quarter 2024 to obtain a 13.01 per cent equity interest in TGNH included consideration of its proportionate share of required capital contributions for approved projects. Net capital expenditures will be adjusted for any new capital projects approved in TGNH going forward.

OUTLOOK

Comparable EBITDA and comparable earnings

We expect our 2026 comparable EBITDA and our 2026 comparable earnings per common share to be higher than 2025 due to the net impact of the following:

- new projects anticipated to be placed in service in 2026, along with the full-year impact of projects placed in service in 2025
- higher revenue from the Columbia Gas settlement
- higher net generation from Bruce Power due to the return to service of Unit 3 from the MCR outage, partially offset by the commencement of the Unit 5 MCR outage
- higher depreciation due to the in-service of Canadian Natural Gas Pipelines and U.S. Natural Gas Pipelines projects
- lower AFUDC primarily due to Southeast Gateway pipeline in-service in 2025.

Consolidated capital expenditures

In 2025, we incurred approximately $5.9 billion in gross capital expenditures on our secured capital program and projects under development, as well as capitalized interest and AFUDC, where applicable. Net capital expenditures after adjusting for the capital expenditures attributable to the non-controlling interests of entities we control were approximately $5.3 billion.

Prior to adjustments for non-controlling interests, we expect to incur gross capital expenditures of approximately $6.0 to $6.5 billion in 2026. We anticipate our net capital expenditures in 2026 to be approximately $5.5 to $6.0 billion.

The majority of our 2026 capital program is focused on the advancement of secured projects including U.S. Natural Gas Pipelines projects, NGTL System expansions, pipeline projects in Mexico, Bruce Power MCR programs and normal course maintenance capital expenditures.

Refer to the Outlook section in each business segment for additional details on expected earnings and capital expenditures for 2026.

CAPITAL PROGRAM

We are developing quality projects under our capital program. These long-life infrastructure assets are supported by long-term commercial arrangements with creditworthy counterparties and/or regulated business models and are expected to generate growth in earnings and cash flows.

Our capital program consists of approximately $21 billion of secured projects that represent commercially supported, committed projects that are either under construction or are in, or preparing to commence the permitting stage.

Three years of maintenance capital expenditures for our businesses are included in the Secured projects table. Maintenance capital expenditures on our regulated Canadian and U.S. natural gas pipelines are added to rate base on which we have the opportunity to earn a return and recover these expenditures through current or future tolls, which is similar to our capacity capital projects on these pipelines.

During 2025, we placed approximately $8.3 billion of projects into service, which included natural gas pipeline capacity projects along our extensive North American asset footprint, including the Southeast Gateway pipeline, as well as progress on the Bruce Power life extension program. In addition, approximately $2.2 billion of maintenance capital expenditures were incurred in the period.

All projects are subject to cost and timing adjustments due to factors including weather, market conditions, route refinement, land acquisition, permitting conditions, scheduling and timing of regulatory permits, as well as other potential restrictions and uncertainties, including inflationary pressures on labour and materials. Amounts exclude capitalized interest and AFUDC, where applicable.

Secured projects

Estimated and incurred project costs referred to in the following table include 100 per cent of the capital expenditures related to projects within entities that we own or partially own and fully consolidate, as well as our share of equity contributions to fund projects within our equity investments.

(billions of Canadian $, unless otherwise noted)	Expected in-service date	Estimated project cost	Project costs incurred at December 31, 2025
Canadian Natural Gas Pipelines[1]			
NGTL System	2026	0.5 [2]	0.4
	2027	0.4 [2]	—
	2028+	0.6 [2]	—
Regulated maintenance capital expenditures	2026-2028	2.6	—
U.S. Natural Gas Pipelines			
Gillis Access – Extension	2026-2027	US 0.4	US 0.1
Heartland project	2027	US 0.9	US 0.1
Northwoods project	2029	US 0.9	—
Pulaski and Maysville projects	2029	US 0.8	—
Southeast Virginia Energy Storage project	2030	US 0.3	—
TCO Connector project	2030	US 0.3	—
Other capital[3]	2026-2031	US 1.9	US 0.4
Regulated maintenance capital expenditures	2026-2028	US 2.6	—
Mexico Natural Gas Pipelines			
Villa de Reyes – South section[4]	—	US 0.4	US 0.3
Tula[5]	—	US 0.4	US 0.3
Power and Energy Solutions			
Bruce Power – Unit 3 MCR	2026	1.1	1.1
Bruce Power – Unit 4 MCR[6]	2028	0.9	0.4
Bruce Power – Unit 5 MCR[6]	2030	1.1	0.2
Bruce Power – life extension[7]	2026-2031	1.5	0.7
Other			
Non-recoverable maintenance capital expenditures[8]	2026-2028	0.5	—
		18.1	4.0
Foreign exchange impact on secured projects[9]		3.3	0.4
Total secured projects		21.4	4.4

1 Our share of committed equity to fund the estimated cost of the Coastal GasLink - Cedar Link project is $37 million.
2 Includes amounts related to projects within the Multi-Year Growth Plan (MYGP) that have received FID.
3 Includes capital expenditures related to certain large-scope maintenance projects across our U.S. natural gas footprint due to their discrete nature for regulatory recovery.
4 We are working with the CFE on completing the remaining section of the Villa de Reyes pipeline. The in-service date will be determined upon resolution of outstanding stakeholder issues.
5 Estimated project cost as per contracts signed in 2022 as part of the TGNH strategic alliance between TC Energy and the CFE. We continue to evaluate the development and completion of the Tula pipeline with the CFE, subject to a future FID and an updated cost estimate.
6 Amounts are net of expected investment tax credits.
7 Reflects amounts to be invested under the Asset Management program to 2027, other life extension projects and the incremental uprate initiative.
8 Includes non-recoverable maintenance capital expenditures from all segments and is primarily related to our Power and Energy Solutions and Corporate assets.
9 Reflects U.S./Canada foreign exchange rate of 1.37 at December 31, 2025.

Projects under development

In addition to our secured projects, we are pursuing a portfolio of quality projects in various stages of development across each of our business units. Projects under development have greater uncertainty with respect to timing and estimated project costs and are subject to company and regulatory approvals, unless otherwise noted. New growth opportunities will be assessed within our disciplined capital allocation framework in order to fit within our annual capital expenditure parameters. As these new opportunities advance and reach required milestones, they will be included in the Secured projects table.

Canadian Natural Gas Pipelines

We continue to focus on optimizing the utilization and value of our existing Canadian Natural Gas Pipelines assets, including sanctioned in-corridor expansions, providing connectivity to LNG export terminals, connecting growing WCSB gas supplies to domestic and export markets and other opportunities, including progressing our Multi-Year Growth Plan (MYGP). The MYGP is comprised of multiple distinct projects with various targeted in-service dates, subject to final company and regulatory approvals.

U.S. Natural Gas Pipelines

We are currently pursuing a variety of projects that are expected to replace, upgrade, expand and extend our U.S. Natural Gas Pipelines footprint. The enhanced facilities associated with these projects are expected to improve the reliability of our systems and provide additional transportation capacity under long-term contracts. We continue to see growing demand across multiple segments, driving potential expansion projects to support new natural gas-fired power generation, coal to natural gas conversions, LDC growth and data centres. Our footprint is well positioned to deliver natural gas supply through our existing utility customer base or by way of direct connections. Additional opportunities include direct and indirect interconnects to deliver natural gas to power generation for data centres, continued LNG development in proximity to our footprint and LDC peak day growth.

Power and Energy Solutions

Bruce Power

Life Extension Program

The continuation of Bruce Power's life extension program will require the investment of our proportionate share of both the MCR program costs on Units 7 and 8 and the remaining Asset Management program costs, which continue beyond the completion of the MCR program in 2033, extending the life of Units 3 to 8 and the Bruce Power site to 2064. Preparation work for the Unit 7 and 8 MCRs is underway and future MCR investments will be subject to discrete decisions for each unit with specified off-ramps available to Bruce Power and the IESO. Refer to the Power and Energy Solutions – Significant events section for additional information.

Energy Solutions

Ontario Pumped Storage

With our prospective partners, Saugeen Ojibway Nation, we continue to advance the Ontario Pumped Storage Project, an energy storage facility located in Meaford, Ontario. The 1,000 MW project is expected to provide enough electricity to power one million homes for up to 11 hours, while enhancing the reliability and efficiency of Ontario's electricity system.

Using water and gravity, the project is like a natural battery that will store surplus electricity when demand is low and later redeploy it during periods of high demand. The project will support the planned buildout of Ontario's nuclear fleet and can deliver Ontario's clean nuclear power on demand.

In January 2025, the Ontario Government announced it was investing up to $285 million to advance pre-development work on the project. With this investment, the project is advancing critical development work, including the completion of a detailed cost estimate, the commencement of federal and provincial environmental assessments, advanced design and engineering and continued community engagement. It is expected that our Board of Directors, Saugeen Ojibway Nation and the Ontario Government will each make a final investment decision on the project following this pre-development work.

NATURAL GAS PIPELINES BUSINESS

Our natural gas pipeline network transports natural gas from supply basins to LDCs, power generation plants, industrial facilities, interconnecting pipelines, LNG export terminals and other businesses across Canada, the U.S. and Mexico. Our network of pipelines taps into most major supply basins and transports over 30 per cent of continental daily natural gas needs through:

- wholly-owned natural gas pipelines – 63,185 km (39,260 miles)
- partially-owned natural gas pipelines – 30,986 km (19,253 miles).

In addition to our natural gas pipelines, we have regulated natural gas storage facilities in the U.S. with a total working gas capacity of 532 Bcf, making us one of the largest providers of natural gas storage and related services to key markets in North America.

Our Natural Gas Pipelines business is split into three operating segments representing its geographic diversity: Canadian Natural Gas Pipelines, U.S. Natural Gas Pipelines and Mexico Natural Gas Pipelines.

Strategy

Our strategy is to maximize the value of our existing natural gas pipeline systems in a safe and reliable manner while responding to the changing flow patterns of natural gas in North America. We also pursue new pipeline opportunities to add incremental value to our business.

Our key areas of focus include:

- primarily in-corridor expansion and extension of our existing significant North American natural gas pipeline footprint
- connections to new and growing industrial and electric power generation markets and LDCs
- expanding our systems in key locations in North America and developing new projects to provide connectivity to LNG export terminals, both operating and proposed
- connections to growing Canadian and U.S. shale gas and other supplies
- minimizing our GHG and methane emissions through operational excellence.

Each of these areas plays a critical role in meeting the transportation requirements for supply of and demand for natural gas in North America.

Our natural gas pipeline systems are helping solve the energy trilemma - energy security, affordability and sustainability. We believe natural gas provides a reliable, high-efficiency energy source that is helping to support the displacement of coal-fired power while backstopping the intermittency of renewable power sources across North America. We continue to improve operational efficiencies and factor sustainability-related considerations into our decision making around new projects, modernization, maintenance, electrification and enhanced leak detection. Our business model provides socioeconomic benefits as we work closely with Indigenous communities, community-based organizations, landowners and other stakeholders in alignment with our values and sustainability commitments.

Recent highlights

Canadian Natural Gas Pipelines

- placed approximately $0.2 billion of capacity capital projects into service in 2025 primarily related to the Valhalla section of NGTL's Valhalla North and Berland River (VNBR) project
- approximately $1.1 billion of MYGP expansion facilities have received FID at December 31, 2025, with in-service dates starting in 2026
- NGTL System achieved record inflows
- continued strong throughput on the Canadian Mainline.

U.S. Natural Gas Pipelines

- placed approximately US$2.7 billion of capital projects in service in 2025, including the East Lateral XPress, VR Project, WR Project, Eastern Panhandle, Ventura XPress and maintenance capital
- sanctioned approximately US$2.3 billion of capital projects including the Northwoods and TCO Connector projects
- Columbia Gas filed a Section 4 Rate Case with FERC in September 2024 requesting an increase to maximum transportation rates effective April 1, 2025 and on October 30, 2025, FERC approved the settlement filing (Columbia Gas Settlement). Previously accrued rate refund liabilities were refunded to customers, including interest, in fourth quarter 2025
- ANR and Great Lakes each filed a Section 4 Rate Case with FERC in April 2025 requesting an increase to their maximum transportation rates effective November 1, 2025, subject to refund. The rate cases are progressing as expected as we continue to pursue a collaborative process through settlement negotiations
- achieved record throughput volumes on a number of our pipelines.

Mexico Natural Gas Pipelines

- the Southeast Gateway Pipeline was completed in May 2025. In July 2025, the newly constituted CNE approved our regulated rates required to provide service to potential future interruptible service users on the Southeast Gateway pipeline other than the CFE
- overall pipeline utilization continued to increase.

UNDERSTANDING OUR NATURAL GAS PIPELINES BUSINESS

Natural gas pipelines move natural gas from major sources of supply to locations or markets that use natural gas to meet their energy needs.

Our natural gas pipelines business builds, owns and operates a network of natural gas pipelines across North America that connects gas production to interconnects, end-use markets and LNG export terminals. The network includes underground pipelines that transport natural gas predominantly under high pressure, compressor stations that act like pumps to move large volumes of natural gas along the pipeline, meter stations that record the amount of natural gas coming on the network at receipt locations and leaving the network at delivery locations and regulated natural gas storage facilities that provide services to customers and help maintain the overall balance of the pipeline systems.

Regulation of tolls and cost recovery

Our natural gas pipelines are generally regulated by the CER in Canada and FERC in the U.S. During March 2025, Mexico natural gas pipeline regulation transitioned from the CRE to the newly constituted CNE under the SENER.

These entities regulate the construction, operation and requested abandonment of pipeline infrastructure. For our rate regulated assets in Canada and the U.S., these regulators allow us to recover costs to operate the network by collecting tolls for services. These tolls generally include a return on our capital invested in the assets or rate base, as well as recovery of the rate base over time through depreciation. Other costs generally recovered through tolls include OM&A, taxes and interest on debt. The regulators generally review our costs to ensure they are reasonable and prudently incurred and approve tolls that provide a reasonable opportunity to recover those costs. In Mexico, while the majority of our capacity is subscribed under a long-term contractual rate, the regulator sets rates for interruptible services.

Business environment and strategic priorities

The North American natural gas pipeline network has been developed to connect diverse supply regions to domestic markets and to meet demand from LNG export facilities. Use and growth of this infrastructure is affected by changes in the location and relative cost of natural gas supplies, as well as changes in the location of markets and level of demand.

We have significant pipeline footprints that serve two of the most prolific supply regions of North America – the WCSB and the Appalachian basin. Our pipelines also source natural gas from other significant basins including the Rockies, Williston, Haynesville, Fayetteville and Anadarko basins. We expect continued growth in North American natural gas production to meet demand within growing domestic markets, particularly in the electric generation and industrial sectors which benefit from a relatively low natural gas price. In addition, North American supply is expected to benefit from increased natural gas demand in Mexico and growing access to international markets via LNG exports. We expect North American natural gas demand, including LNG exports, of approximately 155 Bcf/d by 2029, reflecting an increase of approximately 30 Bcf/d from 2024 levels.

As the world shifts toward a lower-carbon economy, we believe that further retirements of coal-fired power generation as well as export demand growth over the next five to 10 years will offer growth opportunities for base-load power from natural gas-fired generation. We expect that this projected growth in demand for natural gas, coupled with the anticipated increases in key producing areas like WCSB, onshore Gulf Coast, Appalachian and the Permian basin, will provide investment opportunities for pipeline infrastructure companies to build new facilities or increase utilization of their existing footprint. Modernizing our existing systems and assets and decarbonizing our energy consumption along our natural gas pipeline systems is expected to provide ongoing additional capital investment opportunities that will meet our risk preferences while supporting our GHG emissions reduction targets.

Changing demand
The abundant supply of natural gas has supported increased demand, particularly in the following areas:
- natural gas-fired power generation, including for use in emerging data centres
- global LNG exports
- petrochemical and industrial facilities
- Alberta oil sands.

Natural gas producers continue to progress opportunities to sell natural gas to global markets which involves connecting natural gas supplies to LNG export terminals, both operating and proposed, along the U.S. Gulf Coast and the east and west coasts of Canada, the U.S. and Mexico. The increasing export of natural gas to Mexico is driven by the CFE's need to serve existing markets and requires pipelines to serve new regions. We believe that natural gas is a key energy transition fuel for Mexico.

Overall, we are forecasting significant natural gas demand growth in the future to support economic expansion and industrial load growth, conversion to lower GHG emission-intensive fuels for industrial and power generation use and LNG export prospects. The demand created by these new markets provides additional opportunities for us to build new pipeline infrastructure and to increase throughput on our existing pipelines.

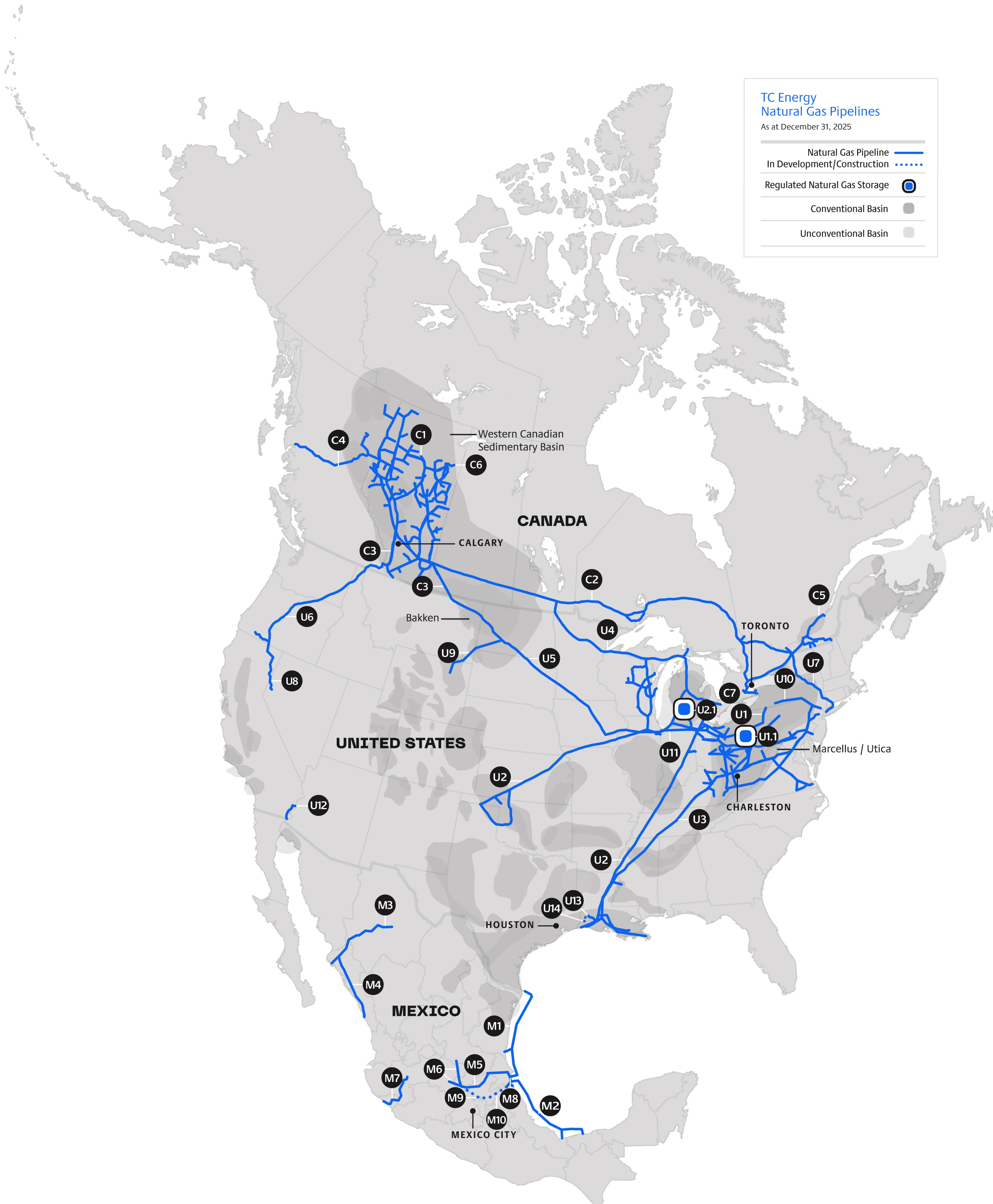
Commodity prices
The profitability of our natural gas pipelines business is not directly tied to commodity prices given we are a transporter of the commodity and the transportation tolls are not tied to the price of natural gas. However, the cyclical supply and demand nature of commodities and related pricing can have an indirect impact on our business where producers may choose to accelerate or delay development of gas reserves or, similarly on the demand side, projects requiring natural gas may be accelerated or delayed depending on market or price conditions.

More competition
Changes in supply and demand levels and locations have resulted in increased competition to provide transportation services throughout North America. Our well-distributed footprint of natural gas pipelines, particularly in the low-cost WCSB and the Appalachian basin, both of which are connected to North American demand centres, has placed us in a strong competitive position. Incumbent pipelines benefit from the connectivity and economies of scale afforded by the base infrastructure, as well as existing right-of-way and operational synergies given the increasing challenges of siting and permitting new pipeline construction and expansions. We have and will continue to offer competitive services to capture growing supply and North American demand that now includes access to global markets through LNG exports.

Strategic priorities
Our pipelines deliver the natural gas that millions of individuals and businesses across North America rely on for their energy needs. We are focused on capturing opportunities resulting from growing natural gas supply and connecting new markets while satisfying increasing demand for natural gas within existing markets. We are also focused on adapting our existing assets to changing natural gas flow dynamics and supporting our corporate-level sustainability commitments and targets.

Our goal is to place all of our projects into service on time and on budget while ensuring the safety of our people, the environment and the general public impacted by the construction and operation of these facilities. In 2026, we will continue to focus on the execution of our existing capital program, which includes initiating and advancing a suite of U.S. pipeline projects as well as investment in Canada, which includes the NGTL System and the Cedar Link project and investment in our Mexico gas pipelines. We will remain focused on capital discipline as we continue to pursue the next wave of growth opportunities.

Our marketing entities will complement our natural gas pipeline operations and generate non-regulated revenues by managing the procurement of natural gas supply and pipeline transportation capacity for natural gas customers within our pipeline corridors.


TC Energy
Natural Gas Pipelines
As at December 31, 2025
Natural Gas Pipeline
In Development/Construction
Regulated Natural Gas Storage
Conventional Basin
Unconventional Basin
CANADA
UNITED STATES
MEXICO
Western Canadian Sedimentary Basin
CALGARY
Bakken
TORONTO
Marcellus / Utica
CHARLESTON
HOUSTON
MEXICO CITY
C1
C2
C3
C3
C4
C5
C6
C7
U1
U1.1
U2
U2
U2.1
U3
U4
U5
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M10

We are the operator of all of the following natural gas pipelines and regulated natural gas storage assets except for Iroquois.

		Length	Description	Ownership
	Canadian pipelines			
C1	NGTL System	24,096 km (14,973 miles)	Receives, transports and delivers natural gas within Alberta and British Columbia, and connects with Canadian Mainline, Coastal GasLink, Foothills and third-party pipelines. This is our natural gas gathering and transportation system for the WCSB, connecting most of the natural gas production in western Canada to domestic and export markets and is well positioned to connect growing supply in northeast British Columbia and northwest Alberta. Our capital program for new pipeline facilities is driven by these two supply areas, along with growing demand for intra-Alberta firm transportation for electric power generation, oil sands development and petro-chemical feedstock, as well as to our major export points at the Empress and Alberta/British Columbia delivery locations. The NGTL System is also well positioned to connect WCSB supply to LNG export facilities on the Canadian west coast through future extensions or expansions of the system or future connections to other pipelines serving that area.	100%
C2	Canadian Mainline	14,087 km (8,753 miles)	Transports natural gas from the Alberta/Saskatchewan border and the Ontario/U.S. border to serve Canadian and U.S. markets. This pipeline supplies markets in the Canadian Prairies, Ontario, Québec, the Canadian Maritimes, as well as to U.S. markets including the Midwest, Gulf Coast and U.S. Northeast from the WCSB and, through interconnects, from the Appalachian basin.	100%
C3	Foothills	1,289 km (801 miles)	Transports natural gas from central Alberta to the U.S. border for export to the U.S. Midwest, Pacific Northwest, California and Nevada.	100%
C4	Coastal GasLink	671 km (417 miles)	Transports natural gas from the Montney region to LNG Canada's liquefaction facility near Kitimat, British Columbia, supplied via connections with the NGTL System and other pipelines.	35%
C5	Trans Québec & Maritimes (TQM)	648 km (403 miles)	Connects with the Canadian Mainline near the Ontario/ Québec border to transport natural gas to the Montréal to Québec City corridor and interconnects with a third-party pipeline at the U.S. border.	50%
C6	Ventures LP	133 km (83 miles)	Transports natural gas to the oil sands region near Fort McMurray, Alberta.	100%
C7	Great Lakes Canada	60 km (37 miles)	Transports natural gas from the Great Lakes system in the U.S. to a point near Dawn, Ontario through a connection at the U.S. border underneath the St. Clair River.	100%
	U.S. pipelines and gas storage assets			
U1	Columbia Gas	18,598 km (11,556 miles)	Transports natural gas primarily from the Appalachian basin, which contains the Marcellus and Utica shale plays, two of the largest natural gas shale plays in North America, to markets and pipeline interconnects throughout the U.S. Northeast, Midwest and Atlantic regions and is well positioned to connect growing supply to markets in this area. This system also interconnects with other pipelines that provide access to key markets in the U.S. Northeast, the Midwest, the Atlantic coast and south to the Gulf of Mexico and its growing demand for natural gas to serve LNG exports.	60%
U1.1	Columbia Storage	285 Bcf	Provides regulated underground natural gas storage service from several facilities (not all shown) to customers in key eastern markets. We own a 60 per cent interest in the 273 Bcf Columbia Storage facility and a 50 per cent interest in the 12 Bcf Hardy Storage facility.	Various

		Length	Description	Ownership
U2	ANR[1]	15,075 km (9,367 miles)	Transports natural gas from various supply basins to markets throughout the U.S. Midwest and U.S. Gulf Coast. This pipeline system connects supply basins and markets throughout the U.S. Midwest and south to the Gulf of Mexico. This includes connecting supply in Texas, Oklahoma, the Appalachian basin and the Gulf of Mexico to markets in Wisconsin, Michigan, Illinois and Ohio. In addition, ANR has bidirectional capability on its Southeast Mainline and delivers gas produced from the Appalachian basin to customers throughout the U.S. Gulf Coast region.	100%
U2.1	ANR Storage	247 Bcf	Provides regulated underground natural gas storage service from several facilities (not all shown) to customers in key mid-western markets.	100%
U3	Columbia Gulf	5,419 km (3,367 miles)	Transports natural gas to various markets and pipeline interconnects in the southern U.S. and U.S. Gulf Coast. This pipeline system transports growing Appalachian basin supplies to various U.S. Gulf Coast markets and LNG export terminals from its interconnections with Columbia Gas and other pipelines.	60%
U4	Great Lakes	3,404 km (2,115 miles)	Connects with the Canadian Mainline near Emerson, Manitoba and to Great Lakes Canada near St Clair, Ontario, plus interconnects with ANR at Crystal Falls and Farwell in Michigan, to transport natural gas to eastern Canada and the U.S. Midwest.	100%
U5	Northern Border	2,272 km (1,412 miles)	Transports WCSB, Bakken and Rockies natural gas from connections with Foothills and Bison to U.S. Midwest markets.	50%
U6	GTN	2,216 km (1,377 miles)	Transports WCSB and Rockies natural gas to Washington, Oregon and California. Connects with Tuscarora and Foothills.	100%
U7	Iroquois	669 km (416 miles)	Connects with the Canadian Mainline and serves markets in New York.	50%
U8	Tuscarora	491 km (305 miles)	Transports natural gas from GTN at Malin, Oregon to markets in northeastern California and northwestern Nevada.	100%
U9	Bison	488 km (303 miles)	Transports natural gas from the Powder River basin in Wyoming to Northern Border in North Dakota.	100%
U10	Millennium	424 km (263 miles)	Transports natural gas primarily sourced from the Marcellus shale play to markets across southern New York and the lower Hudson Valley, as well as to New York City through its pipeline interconnections.	47.5%
U11	Crossroads	325 km (202 miles)	Interstate natural gas pipeline operating in Indiana and Ohio with multiple interconnects to other pipelines.	100%
U12	North Baja[1]	138 km (86 miles)	Transports natural gas between Arizona and California and connects with a third-party pipeline on the California/Mexico border.	100%
U13	Gillis Access	68 km (42 miles)	A pipeline system that connects supplies from the Haynesville basin at Gillis, Louisiana to markets elsewhere in Louisiana.	100%

		Length	Description	Ownership
Mexico pipelines				
M1	Sur de Texas	770 km (478 miles)	Offshore pipeline that transports natural gas from the U.S./ Mexican border near Brownsville, Texas, to Mexican power plants in Altamira, Tamaulipas and Tuxpan, Veracruz, where it interconnects with the Tamazunchale and Tula pipelines and other third-party facilities. This offshore pipeline transports natural gas from the Texas border to power and industrial markets in the eastern and central regions of Mexico.	60%
M2	Southeast Gateway	715 km (444 miles)	Offshore pipeline that connects to the Tula pipeline and transports gas to delivery points in Coatzacoalcos, Veracruz and Paraíso, Tabasco in Mexico's southeast region.	86.99%
M3	Topolobampo	572 km (355 miles)	Transports natural gas to El Oro and Topolobampo, Sinaloa, from interconnects with third-party pipelines in El Encino, Chihuahua and El Oro. The system supplies power plants and industrial facilities.	100%
M4	Mazatlán	430 km (267 miles)	Transports natural gas from El Oro to Mazatlán, Sinaloa, interconnects with third-party pipelines and connects to the Topolobampo pipeline at El Oro. The system supplies power plants and industrial facilities.	100%
M5	Tamazunchale	370 km (230 miles)	Transports natural gas from Naranjos, Veracruz and Higueros (Sur de Texas-Tuxpan System) to Tamazunchale, San Luis Potosi and on to El Sauz, Querétaro in central Mexico. The system supplies power plants and industrial facilities.	86.99%
M6	Villa de Reyes – North and Lateral sections	316 km (196 miles)	The north and lateral sections of the Villa de Reyes pipeline are interconnected to our Tamazunchale pipeline and third-party systems, supporting gas deliveries to power plants in Villa de Reyes, San Luis Potosí and Salamanca, Guanajuato.	86.99%
M7	Guadalajara	313 km (194 miles)	Bidirectional pipeline that connects imported LNG supply near Manzanillo and continental gas supply near Guadalajara to power plants and industrial customers in the states of Colima and Jalisco.	100%
M8	Tula – East section	114 km (71 miles)	The east section of the Tula pipeline transports natural gas from Sur de Texas to power plants in Tuxpan, Veracruz.	86.99%
Under construction				
Canadian pipelines				
	NGTL System[2,3,4]	35 km (22 miles)	Includes expansion facilities, the Berland River compressor unit of the VNBR project and portions of the MYGP, with targeted in-service dates beginning in 2026.	100%
	Coastal GasLink – Cedar Link project[2,3]	n/a	The Cedar Link project is an expansion of the Coastal GasLink pipeline that is expected to enable delivery of up to 0.4 Bcf/d of natural gas to the Cedar LNG facility. This includes the addition of a new compressor station, connector pipeline and meter station to Coastal GasLink's existing pipeline infrastructure, which is expected to be placed in service in 2028.	35%

	Under construction (continued)	Length	Description	Ownership
	U.S. pipelines			
U14	Gillis Access – Extension[2,3]	63 km (39 miles)	An extension of Gillis Access to further connect supplies from Haynesville basin at Gillis with anticipated in-service dates starting in late 2026.	100%
	Bison XPress Project[1,2]	n/a	A project with Northern Border, a 50 per cent owned subsidiary, and Bison, a wholly-owned subsidiary, that will replace and upgrade certain facilities while improving reliability, which is expected to be placed in service in 2026.	Various
	Mexico pipelines			
M9	Villa de Reyes – South section	110 km (68 miles)	This pipeline section will connect to the operational north and lateral sections of the Villa de Reyes pipeline and to the Tula pipeline.	86.99%
	Permitting and pre-construction phase			
	Canadian pipelines			
	NGTL System – MYGP[2,3,4]	54 km (34 miles)	Includes portions of the MYGP expansion facilities with targeted in-service dates beginning in 2027.	100%
	U.S. pipelines			
	Pulaski Project[2,3]	64 km (40 miles)	A pipeline extension project on our Columbia Gulf system designed to serve existing power plants. The project is expected to be placed in service in 2029.	60%
	Maysville Project[2,3]	64 km (40 miles)	A pipeline extension project on our Columbia Gulf system designed to serve existing power plants. The project is expected to be placed in service in 2029.	60%
	TCO Connector	45 km (28 miles)	A pipeline extension project on our Columbia Gas system designed to service a new gas-fired power plant. The project is expected to be placed in service 2030.	60%
	Southeast Virginia Energy Storage Project[2]	1.1 Bcf	An LNG storage facility located on our Columbia Gas system in southeast Virginia designed to serve an existing LDC's growing market. The project is expected to be placed in service in 2030.	60%
	Heartland Project[1,2]	n/a	An expansion project on our ANR system that is designed to increase capacity and improve system reliability with upgrades to compression facilities, expected to be placed in service in 2027.	100%
	Northwoods Project[1,2]	n/a	An expansion project on our ANR system that is designed to increase capacity to serve natural gas-fired electric generation demand in the U.S. Midwest, including data centres and overall economic growth. The project is expected to be placed in service in 2029.	100%
	Mexico pipelines			
M10	Tula[3]	100 km (62 miles)	TC Energy and the CFE are assessing options to complete the remaining sections of the pipeline, which are subject to FID.	86.99%

1 Includes compressor station modifications, additions and/or expansion projects with no additional pipe length.
2 Facilities and some pipelines are not shown on the map.
3 Final pipe lengths are subject to change during construction and/or final design considerations.
4 Includes projects within the MYGP that have received FID.

Canadian Natural Gas Pipelines

UNDERSTANDING OUR CANADIAN NATURAL GAS PIPELINES SEGMENT

The Canadian Natural Gas Pipelines business is subject to regulation by various federal and provincial governmental agencies. The CER has jurisdiction over our regulated Canadian natural gas interprovincial pipeline systems, while provincial regulators have jurisdiction over pipeline systems operating entirely within a single province. All of our major Canadian natural gas pipeline assets are regulated by the CER with the exception of the Coastal GasLink pipeline, which is regulated by the BC Energy Regulator.

For the interprovincial natural gas pipelines it regulates, the CER approves tolls, facilities and services that are in the public interest and provide a reasonable opportunity for the pipeline to recover its costs to operate the pipeline. Included in the overall toll is a return on the investment we have made in the assets, referred to as the return on equity. Generally, the CER has approved a deemed capital structure of 40 per cent equity and 60 per cent debt. Typically, tolls are based on the cost of providing service, including the cost of financing, divided by a forecast of volumes. Any variance in either costs or the actual volumes transported can result in an over-collection or under-collection of revenues that is normally trued up the following year in the calculation of the tolls for that period. The return on equity, however, would continue to be earned at the rate approved by the CER.

Subject to approval by the CER, we and our customers can also establish settlement arrangements that may have elements that vary from the typical toll-setting process. Settlements can include longer terms and mechanisms such as incentive agreements that can have an impact on the actual return on equity achieved. Examples include fixing the OM&A component in determining revenue requirements where variances are to the pipeline's account or shared between the pipeline and shippers.

The NGTL System is operating under the CER approved five-year negotiated revenue requirement settlement for 2025-2029 (the 2025-2029 NGTL Settlement), which commenced on January 1, 2025 and includes an approved ROE of 10.1 per cent on 40 per cent deemed common equity. This settlement provides the NGTL System with higher depreciation rates and the opportunity to further increase depreciation rates with an incentive if tolls fall below specified levels, or if growth projects are undertaken. It also includes incentive mechanisms to reduce both physical emissions and emission compliance costs, while also providing incentive for certain operating costs where variances from projected amounts and emissions savings are shared with customers. The Canadian Mainline is operating under the 2021-2026 Mainline settlement, which includes an incentive to decrease costs and increase revenues.

SIGNIFICANT EVENTS

NGTL System

In the year ended December 31, 2025, the NGTL System placed approximately $0.2 billion of capacity projects in service.

Multi-Year Growth Plan

The 2025-2029 NGTL Settlement enables an investment framework that supports our Board of Directors' approval to allocate up to $3.3 billion of capital towards progression of the MYGP for expansion facilities to meet commitments on the NGTL System. It is comprised of multiple distinct projects with various targeted in-service dates, subject to final company and regulatory approvals. To date, approximately $1.1 billion of MYGP expansion facilities have received FID, with various in-service dates starting in 2026. We continue to evaluate plans for each MYGP facility to optimize cost and schedule. Completion of the MYGP is expected to enable approximately 1.0 Bcf/d of incremental system throughput.

Valhalla North and Berland River Project

We continue to advance construction of the Valhalla North and Berland River project. The Valhalla section, which consists of approximately 33 km (21 miles) of new pipeline, was placed in service in third quarter 2025, with a capital cost of approximately $0.2 billion. The Berland River section, which includes a new non-emitting electric compressor unit and associated facilities, has a target in-service date in the second half of 2026 and an estimated capital cost of $0.3 billion. The project is designed to provide incremental capacity on the NGTL System of approximately 428 TJ/d (400 MMcf/d).

Coastal GasLink

Coastal GasLink Pipeline

In October 2025, pursuant to the November 2024 commercial agreement executed with LNG Canada (LNGC) and each of the five LNGC participants, TC Energy received a one-time payment of $199 million in recognition of completed work and final cost settlement. This payment was recognized by TC Energy as an in-substance distribution from Coastal GasLink LP in our 2024 Consolidated financial statements.

Reclamation activities associated with post-construction work were completed in 2025. In addition, Coastal GasLink LP has resolved all material claims with a net positive recovery overall to Coastal GasLink LP. Refer to Note 30, Commitments, contingencies and guarantees, of our 2025 Consolidated financial statements for additional information.

Indigenous Equity Option

In March 2022, we announced the signing of option agreements to sell up to a 10 per cent equity interest in Coastal GasLink LP to Indigenous communities across the project corridor, from our current 35 per cent equity ownership. In January 2026, prospective investors entered into a binding window for these options, which is expected to remain in effect through to the end of 2026. Closing of the equity sale is subject to customary regulatory approvals and consents, including the consent of LNGC.

FINANCIAL RESULTS

The following is a reconciliation of comparable EBITDA and comparable EBIT (our non-GAAP measures) to segmented earnings (losses) (the most directly comparable GAAP measure). Refer to page 22 for more information on non-GAAP measures we use.

year ended December 31 (millions of $)	**2025**	**2024**	**2023**
NGTL System	**2,586**	2,393	2,201
Canadian Mainline	**817**	787	789
Other Canadian pipelines[1]	**284**	208	345
Comparable EBITDA	**3,687**	3,388	3,335
Depreciation and amortization	**(1,523)**	(1,382)	(1,325)
Comparable EBIT	**2,164**	2,006	2,010
Specific items:			
Gain on sale of non-core assets	**—**	10	—
Coastal GasLink impairment charge	**—**	—	(2,100)
Segmented earnings (losses)	**2,164**	2,016	(90)

1 Includes results from Foothills, Ventures LP, Great Lakes Canada and our proportionate share of income related to investments in TQM and Coastal GasLink, as well as general and administrative and business development costs related to our Canadian natural gas pipelines.

Canadian Natural Gas Pipelines segmented earnings were $2.2 billion in 2025 compared to $2.0 billion in 2024 and segmented losses of $0.1 billion in 2023, and included the following specific items, which have been excluded from our calculation of comparable EBITDA and comparable EBIT:

- a pre-tax gain on sale of non-core assets of $10 million in second quarter 2024
- a pre-tax impairment charge in 2023 of $2.1 billion related to our equity investment in Coastal GasLink LP.

Net income for our rate-regulated Canadian natural gas pipelines is primarily affected by our approved ROE, investment base, the level of deemed common equity and incentive earnings. Comparable EBITDA is impacted by these factors, as well as changes in depreciation, financial charges and income taxes. These additional items do not have a significant impact on net income as they are almost entirely recovered in revenues on a flow-through basis.

Net income and average investment base

year ended December 31 (millions of $)	**2025**	**2024**	**2023**
Net income			
NGTL System	**804**	775	770
Canadian Mainline	**258**	244	230
Average investment base			
NGTL System	**19,277**	19,334	19,008
Canadian Mainline	**3,762**	3,697	3,709

Net income for the NGTL System increased by $29 million in 2025 compared to 2024 primarily due to higher incentive earnings and increased by $5 million in 2024 compared to 2023 mainly due to a higher average investment base resulting from continued system expansions, partially offset by an incentive loss. The NGTL System is currently operating under the 2025-2029 NGTL Settlement, which commenced on January 1, 2025 and includes an approved ROE of 10.1 per cent on 40 per cent deemed common equity. This settlement provides the NGTL System with higher depreciation rates and the opportunity to further increase depreciation rates with an incentive if tolls fall below specified levels, or if growth projects are undertaken. It also includes incentive mechanisms to reduce both physical emissions and emission compliance costs, while also providing an incentive for certain operating costs where variances from projected amounts and emissions savings are shared with customers. Refer to the Canadian Natural Gas Pipelines - Significant events section for additional information.

Net income for the Canadian Mainline increased by $14 million in 2025 compared to 2024 and by $14 million in 2024 compared to 2023 mainly as a result of higher incentive earnings. The Canadian Mainline is operating under the 2021-2026 Mainline Settlement, which includes an approved ROE of 10.1 per cent on 40 per cent deemed common equity and an incentive to decrease costs and increase revenues on the pipeline under a beneficial sharing mechanism with our customers.

Comparable EBITDA

Comparable EBITDA for Canadian Natural Gas Pipelines was $299 million higher in 2025 compared to 2024 primarily due to:

- higher flow-through depreciation and income taxes as well as higher incentive earnings, partially offset by lower flow-through financial charges and lower rate base earnings on the NGTL System
- higher contributions from Coastal GasLink mainly resulting from the declared commercial in-service of the pipeline in fourth quarter 2024
- higher incentive earnings, flow-through depreciation and income taxes on the Canadian Mainline.

Comparable EBITDA for Canadian Natural Gas Pipelines in 2024 was $53 million higher than 2023 primarily due to the net effect of:

- higher flow-through income taxes, depreciation and financial charges, as well as higher rate-base earnings on the NGTL System due to continued system expansions
- higher flow-through income taxes, financial charges and depreciation, as well as higher rate-base earnings on Foothills primarily due to the NGTL System/Foothills West Path Delivery Program completed in 2023
- earnings from Coastal GasLink in 2023 related to the recognition of a $200 million incentive payment upon meeting certain milestones.

Depreciation and amortization

Depreciation and amortization was $141 million higher in 2025 compared to 2024, primarily reflecting higher depreciation rates on the NGTL System under the 2025-2029 NGTL Settlement. Depreciation and amortization was $57 million higher in 2024 compared to 2023, mainly due to incremental depreciation on the NGTL System from expansion facilities that were placed in service.

OUTLOOK

Comparable EBITDA and comparable earnings

Net income for Canadian rate-regulated pipelines is affected by changes in investment base, ROE and deemed capital structure, as well as by the terms of toll settlements approved by the CER. Under the current regulatory model, return on rate base from Canadian rate-regulated natural gas pipelines is not materially affected by short-term fluctuations in the commodity price of natural gas, changes in throughput volumes or changes in contracted capacity levels.

Canadian Natural Gas Pipelines comparable EBITDA in 2026 is expected to be higher than 2025 mainly due to higher contributions from the NGTL System. Due to the flow-through treatment of certain costs on our Canadian rate-regulated pipelines, changes in these costs can impact our comparable EBITDA despite having no significant effect on comparable earnings. We expect our comparable earnings in 2026 for the NGTL System and the Canadian Mainline to be consistent with 2025.

Capital expenditures

We incurred $1.3 billion of capital expenditures in 2025 in our Canadian Natural Gas Pipelines business on growth projects and maintenance capital expenditures. We expect to incur approximately $1.5 billion in 2026, primarily on NGTL System expansion projects and maintenance capital expenditures, all of which are immediately reflected in investment base and related earnings.

U.S. Natural Gas Pipelines

UNDERSTANDING OUR U.S. NATURAL GAS PIPELINES SEGMENT

The U.S. interstate natural gas pipeline business is subject to regulation by various federal, state and local governmental agencies. FERC, however, has comprehensive jurisdiction over our U.S. interstate natural gas business. FERC approves maximum transportation rates that are cost-based and are designed to recover the pipeline's investment, operating expenses and a reasonable return for our investors. In the U.S., we have the ability to contract for negotiated or discounted rates with shippers.

FERC does not require U.S. interstate pipelines to calculate rates annually, nor do they generally allow for the collection or refund of the variance between actual and expected revenues and costs into future years. This difference in U.S. regulation from the Canadian regulatory environment puts our U.S. pipelines at risk for the difference in expected and actual costs and revenues between rate cases. If revenues no longer provide a reasonable opportunity to recover our costs, we can file with FERC for a new determination of rates, subject to any moratorium in effect. Similarly, FERC or our shippers may institute proceedings to lower rates if they consider the return on capital invested to be unjust or unreasonable.

Similar to Canada, we can also establish settlement arrangements with our U.S. shippers that are ultimately subject to approval by FERC. Rate case moratoriums for a period of time, before either we or the shippers can file for a rate review, are common for a settlement in that they provide some certainty for shippers in terms of rates, eliminate the costs associated with frequent rate proceedings for all parties and can provide an incentive for pipelines to lower costs.

PHMSA Pipeline Safety Regulations

Most of our U.S. natural gas pipeline systems are subject to federal pipeline safety statutes and regulations enacted and administered by PHMSA. PHMSA will continue to produce new rules affecting numerous aspects of operation and maintenance of our pipeline system. PHMSA’s priorities are generally dictated by legislation which is influenced by numerous stakeholders and informed by learnings from recent industry incidents and stakeholder priorities. When PHMSA implements new rules, TC Energy seeks recovery of additional expenditures driven by such rules in future rate cases and modernization settlements.

SIGNIFICANT EVENTS

Columbia Gas Section 4 Rate Case

Columbia Gas reached a settlement with its customers effective April 2025 and received FERC approval in October 2025. As part of the settlement, there is a moratorium on any further rate changes until March 31, 2028. Columbia Gas must file for new rates with an effective date no later than April 1, 2031. The settlement also included additional rate step ups in April 2026 and April 2027 to reflect anticipated modernization-related spend. In fourth quarter 2025, previously accrued rate refund liabilities, including interest, were refunded to customers.

ANR and Great Lakes Section 4 Rate Cases

In April 2025, ANR and Great Lakes each filed Section 4 Rate Cases with FERC requesting an increase to their respective maximum transportation rates effective November 1, 2025, subject to refund. We will pursue a collaborative process to find a mutually beneficial outcome with our customers through settlement.

Northwoods Project

In April 2025, we approved the Northwoods project, an expansion project on our ANR system designed to provide 0.4 Bcf/d of capacity to serve natural gas-fired electric generation demand in the U.S. Midwest, including data centres and overall economic growth. The project involves pipeline looping, compressor facility additions as well as other system updates, with an anticipated in-service date of late 2029 and an estimated project cost of approximately US$0.9 billion.

East Lateral XPress

The East Lateral XPress project, an expansion project on the Columbia Gulf system that connects supply to U.S. Gulf Coast LNG export markets, was placed in service in May 2025, with a total project cost of approximately US$0.3 billion.

Ventura XPress Project

The Ventura XPress project, a set of ANR projects designed to improve base system reliability and allow for additional long-term contracted transportation services to a point of delivery on the Northern Border pipeline at Ventura, Iowa, was placed in service in October 2025 with a total project cost of approximately US$0.2 billion.

TCO Connector Project

In October 2025, we approved the TCO Connector project on our Columbia Gas system. This project is designed to provide approximately 0.5 Bcf/d of capacity to serve new natural gas-fired power generation supporting forecasted electric generation growth, including expected data centre growth across our system. The project has an anticipated in-service date of 2030 and an estimated project cost of approximately US$0.3 billion.

VR and WR Projects

In November 2025, we placed the VR and WR projects into service. The VR project, provides incremental capacity from Greensville County, Virginia to delivery points in Norfolk, Virginia, with a total project cost of approximately US$0.5 billion. The WR project, provides mainline capacity to multiple points of delivery on our ANR System in Wisconsin with a total project cost of approximately US$0.7 billion.

FINANCIAL RESULTS

The following is a reconciliation of comparable EBITDA and comparable EBIT (our non-GAAP measures) to segmented earnings (losses) (the most directly comparable GAAP measure). Refer to page 22 for more information on non-GAAP measures we use.

year ended December 31 (millions of US$, unless otherwise noted)	2025	2024	2023
Columbia Gas[1]	**1,803**	1,600	1,530
ANR	**651**	642	650
Columbia Gulf[1]	**235**	235	208
Great Lakes	**191**	204	183
GTN	**263**	188	202
PNGTS[1,2]	**—**	66	104
Other U.S. pipelines[3]	**363**	359	371
Comparable EBITDA	**3,506**	3,294	3,248
Depreciation and amortization	**(743)**	(697)	(692)
Comparable EBIT	**2,763**	2,597	2,556
Foreign exchange impact	**1,106**	959	895
Comparable EBIT (Cdn$)	**3,869**	3,556	3,451
Specific items:			
Gain on sale of PNGTS	**—**	572	—
Gain on sale of non-core assets	**—**	38	—
Risk management activities	**58**	(113)	80
Segmented earnings (losses) (Cdn$)	**3,927**	4,053	3,531

1 Includes non-controlling interest. Refer to the Corporate - Financial results section for additional information.
2 The sale of PNGTS was completed in August 2024.
3 Reflects comparable EBITDA from our ownership in our mineral rights business (CEVCO), North Baja, Gillis Access, Tuscarora, Bison, Crossroads and our share of equity income from Northern Border, Iroquois, Millennium and Hardy Storage, our U.S. natural gas marketing business, as well as general and administrative and business development costs related to our U.S. natural gas pipelines.

U.S. Natural Gas Pipelines segmented earnings in 2025 decreased by $126 million compared to 2024 and increased by $522 million in 2024 compared to 2023 and included the following specific items, which have been excluded from our calculation of comparable EBITDA and comparable EBIT:

- a pre-tax gain of $572 million related to the sale of PNGTS in August 2024
- a pre-tax gain on sale of a non-core asset of $38 million in second quarter 2024
- unrealized gains and losses from changes in the fair value of derivatives used in our U.S. natural gas marketing business.

A stronger U.S. dollar in 2025 and 2024 had a positive impact on the Canadian dollar equivalent segmented earnings from our U.S. dollar-denominated operations. Refer to the Foreign exchange section for additional information.

Earnings from our U.S. Natural Gas Pipelines operations are generally affected by contracted volume levels, volumes delivered and the rates charged, as well as by the cost of providing services. Columbia Gas and ANR results are also affected by the contracting and pricing of their natural gas storage capacity and incidental commodity sales. Natural gas pipeline and storage volumes and revenues are generally higher in the winter months because of the seasonal nature of the business.

Comparable EBITDA for U.S. Natural Gas Pipelines was US$212 million higher in 2025 than 2024 primarily due to the net effect of:
- a net increase in earnings from Columbia Gas as a result of higher transportation rates effective April 1, 2025, pursuant to the Columbia Gas Settlement. Refer to the U.S. Natural Gas Pipelines – Significant events section for additional information
- incremental earnings from projects placed in service, as well as increased earnings from additional contract sales on GTN
- increased earnings from our mineral rights business due to higher commodity prices
- decreased earnings as a result of the sale of our 61.7 per cent equity interest in PNGTS, which was completed in August 2024
- decreased equity earnings from Iroquois and Millennium
- decreased earnings due to higher operational costs, reflective of system utilization and projects placed in service across our footprint.

Comparable EBITDA for U.S. Natural Gas Pipelines was US$46 million higher in 2024 than 2023 primarily due to the net effect of:
- incremental earnings from growth and modernization projects placed in service, as well as increased earnings from additional contract sales on ANR and Great Lakes
- increased equity earnings from Northern Border
- decreased earnings due to higher operational costs, reflective of increased system utilization across our footprint
- decreased earnings as a result of the sale of our 61.7 per cent equity interest in PNGTS, which was completed in August 2024
- lower realized earnings related to our U.S. natural gas marketing business primarily due to lower margins
- reduced earnings from our mineral rights business due to lower commodity prices.

Depreciation and amortization

Depreciation and amortization was US$46 million higher in 2025 compared to 2024 and US$5 million higher in 2024 compared to 2023. The increase in depreciation is primarily due to new projects placed in service and depreciation rate changes as a result of the Columbia Gas Settlement, partially offset by the impact of the sale of PNGTS in 2024.

OUTLOOK

Comparable EBITDA

Our U.S. natural gas pipelines are largely backed by long-term take-or-pay contracts that are expected to deliver stable and consistent financial performance. Our ability to retain customers and recontract or sell capacity at favourable rates is influenced by prevailing market conditions and competitive factors, including alternatives available to end-use customers in the form of competing natural gas pipelines and supply sources, as well as broader conditions that impact demand from certain customers or market segments. Comparable EBITDA is also affected by operational and other costs, which can be impacted by safety, environmental and other regulatory decisions, as well as customer credit risk.

U.S. Natural Gas Pipelines comparable EBITDA in 2026 is expected to be higher than 2025 primarily due to full year in-service of the East Lateral XPress, Ventura XPress, VR and WR projects, as well as a full year of increased rates on Columbia Gas as a result of the Columbia Gas Settlement. Our pipeline systems continue to see historically strong demand for service and we anticipate that during 2026, our assets will maintain the high utilization levels experienced in 2025. These positive results are expected to be partially offset by higher operational costs, reflective of continued increases to system utilization across our footprint and an anticipated increase in property taxes from capital projects placed in service.

Capital expenditures

We incurred a total of US$2.4 billion of capital expenditures in 2025 on our U.S. natural gas pipelines and expect to incur approximately US$2.4 billion in 2026 primarily on our Columbia Gas and ANR expansion projects and Gillis Access expansion project, as well as Columbia Gas and ANR maintenance capital expenditures, the return on and recovery of which, is expected to be reflected in future tolls. We expect net capital expenditures in 2026 to be approximately US$2.0 billion after considering capital expenditures attributable to the non-controlling interests of entities we control.

Mexico Natural Gas Pipelines

UNDERSTANDING OUR MEXICO NATURAL GAS PIPELINES SEGMENT

For over a decade, Mexico has been undergoing a significant transition from fuel oil and diesel as its primary energy sources for electric generation to using natural gas. As a result, new natural gas pipeline infrastructure has been and continues to be required to meet the growing demand for natural gas. The CFE, Mexico's state-owned electric utility, is the primary counterparty on all of our existing pipelines under long-term contracts, which are predominately denominated in U.S. dollars. These fixed-rate contracts are generally designed to recover the cost of service and provide a return on and of invested capital. As the pipeline developer and operator, we are generally at risk for operating and construction costs. Our Mexico pipelines also have regulatory approved tariffs, services and related rates for other potential users.

SIGNIFICANT EVENTS

TGNH Strategic Alliance with the CFE

The Southeast Gateway pipeline is in service and we commenced the collection of tolls beginning May 2025. In July 2025, the newly constituted CNE approved our regulated rates required to provide service to potential future interruptible service users on the Southeast Gateway pipeline other than the CFE.

In 2024, the CFE became an equity partner in TGNH with a 13.01 per cent equity interest. The CFE's equity in TGNH is expected to increase to a maximum of 15 per cent, subject to regulatory approvals, and will increase to approximately 35 per cent upon expiry of the contract in 2055.

FINANCIAL RESULTS

The following is a reconciliation of comparable EBITDA and comparable EBIT (our non-GAAP measures) to segmented earnings (losses) (the most directly comparable GAAP measure). Refer to page 22 for more information on non-GAAP measures we use.

year ended December 31 (millions of US$, unless otherwise noted)	**2025**	**2024**	**2023**
TGNH[1,2]	**625**	231	232
Sur de Texas[3]	**79**	220	75
Topolobampo	**154**	156	157
Guadalajara	**57**	56	61
Mazatlán	**66**	67	71
Comparable EBITDA	**981**	730	596
Depreciation and amortization	**(69)**	(67)	(66)
Comparable EBIT	**912**	663	530
Foreign exchange impact	**357**	244	186
Comparable EBIT (Cdn$)	**1,269**	907	716
Specific item:			
Expected credit loss provision on net investment in leases and certain contract assets in Mexico[2]	**(83)**	22	80
Segmented earnings (losses) (Cdn$)	**1,186**	929	796

1 Includes the operating sections of the Tamazunchale, Villa de Reyes, Tula and Southeast Gateway pipelines.
2 Includes non-controlling interest. Refer to the Corporate - Financial results section for additional information.
3 Represents equity income from our 60 per cent interest and fees earned from the construction and operation of the pipeline.

Mexico Natural Gas Pipelines segmented earnings in 2025 increased by $257 million compared to 2024 and increased by $133 million in 2024 compared to 2023 and included an expense of $83 million in 2025 (2024 – $22 million recovery; 2023 – $80 million recovery) on the expected credit loss provision related to the TGNH net investment in leases and certain contract assets in Mexico, which we have excluded from our calculation of comparable EBITDA and comparable EBIT. Refer to Note 27, Risk management and financial instruments, of our 2025 Consolidated financial statements for additional information.

A stronger U.S. dollar in 2025 and 2024 had a positive impact on the Canadian dollar equivalent segmented earnings from our U.S. dollar-denominated operations in Mexico. Refer to the Foreign exchange section for additional information.

Comparable EBITDA for Mexico Natural Gas Pipelines increased by US$251 million in 2025 compared to 2024 mainly due to the net effect of:

- higher earnings in TGNH due to the completion of the Southeast Gateway pipeline in second quarter 2025
- lower equity earnings from Sur de Texas primarily due to the foreign exchange impacts on the revaluation of peso-denominated liabilities as a result of a stronger Mexican peso and higher income tax expense mainly related to the foreign exchange impacts of U.S. dollar-denominated liabilities.

Comparable EBITDA for Mexico Natural Gas Pipelines increased by US$134 million in 2024 compared to 2023 primarily due to:

- higher equity earnings in Sur de Texas primarily due to the foreign exchange impacts on the revaluation of peso-denominated liabilities as a result of a weaker Mexican peso and lower income tax expense mainly related to the foreign exchange impacts of U.S. dollar-denominated liabilities
- lower earnings from Guadalajara primarily due to lower fixed revenue in accordance with the transportation contract and higher operating costs.

Depreciation and amortization

Depreciation and amortization was generally consistent between 2025 and 2024 and between 2024 and 2023. Under sales-type lease accounting, our in-service TGNH pipeline assets are derecognized from Plant, property and equipment and recorded as a net investment in lease on our Consolidated balance sheet with no depreciation expense being recognized.

Sur de Texas results

Sur de Texas results reflect equity income from our 60 per cent interest and fees earned from the construction and operation of the pipeline. We use foreign exchange derivatives to manage Sur de Texas' foreign exchange exposures, and the impact of these derivatives is recognized in Foreign exchange (gains) losses, net in the Consolidated statement of income. Refer to the Foreign exchange section for additional information.

The following table details our proportionate share of equity income and the foreign exchange impact on Sur de Texas equity earnings from changes in the value of the Mexican peso against the U.S. dollar:

year ended December 31 (millions of US$)	**2025**	**2024**	**2023**
Equity income before foreign exchange impact	**136**	137	137
Foreign exchange impact included in equity earnings	**(57)**	83	(62)
Comparable EBITDA - Sur de Texas	**79**	220	75

OUTLOOK

Comparable EBITDA

Mexico Natural Gas Pipelines comparable EBITDA reflects long-term, stable, principally U.S. dollar-denominated transportation contracts that are affected by the cost of providing service and includes our share of equity income from our 60 per cent equity interest in the Sur de Texas pipeline. Due to the long-term nature of the underlying transportation contracts, comparable EBITDA is generally consistent year-over-year except when new assets are placed in service. Comparable EBITDA for 2026 is expected to be higher than 2025 due to the Southeast Gateway project, which was completed in second quarter 2025.

Capital expenditures

We incurred US$0.2 billion of capital expenditures in 2025 primarily related to the construction of the Southeast Gateway pipeline and maintenance capital expenditures. We expect to incur approximately US$0.2 billion in 2026 to finalize construction of pipeline projects in Mexico.

NATURAL GAS PIPELINES – BUSINESS RISKS

The following are risks specific to our Natural Gas Pipelines business. Refer to page 94 for information about general risks related to TC Energy as a whole, including other operational, safety and financial risks, as well as our approach to risk management.

Production levels within supply basins

The NGTL System and our pipelines downstream depend largely on supply from the WCSB. Columbia Gas and its connecting pipelines largely depend on Appalachian supply. We continue to monitor any changes in our customers' natural gas production plans and how these may impact our existing assets and new project schedules. There is competition amongst pipelines to connect to major basins. An overall decrease in production and/or increased competition for supply could reduce throughput on our connected pipelines that, in turn, could negatively impact overall revenues generated. The WCSB and Appalachian basins are two of the most prolific and cost-competitive basins in North America and have considerable natural gas reserves. However, the amount actually produced depends on many variables including the price of natural gas and natural gas liquids, basin-on-basin competition, pipeline and gas-processing tolls, demand within the basin, changes in policy and regulations and the overall value of the reserves, including liquids content.

Market access

We compete for market share with other natural gas pipelines. New supply basins are being developed closer to markets we have historically served and may reduce the throughput and/or distance of haul on our existing pipelines and impact revenues. New markets, including those created by LNG export facilities developed to access global natural gas demand, can lead to increased revenues through higher utilization of existing facilities and/or demand for new infrastructure. The long-term competitiveness of our pipeline systems and the avoidance of bypass pipelines will depend on our ability to adapt to changing flow patterns by offering competitive transportation services to the market. As part of our annual strategic planning process, we evaluate the resilience of our asset portfolio over a range of potential energy supply and demand outcomes.

Competition for greenfield pipeline expansion

We face competition from other pipeline companies seeking to invest in greenfield natural gas pipeline development opportunities. This competition could result in fewer available projects that meet our investment hurdles or projects that proceed with lower overall financial returns. While renewable deployments are expected to garner an increasing portion of future energy needs, including in the power generation sector, aggregate natural gas demand across all sectors, including LNG exports, is still projected to grow under the most aggressive renewable deployment forecasts. The reliability of natural gas is an important factor in the successful wide-scale deployment of renewables with more intermittent capabilities.

Demand for pipeline capacity

Demand for pipeline capacity ultimately drives the sale of pipeline transportation services and is impacted by supply and market competition, variations in economic activity, weather variability, natural gas pipeline and storage competition, energy conservation, as well as demand for and prices of alternative sources of energy. Renewal of expiring contracts and the opportunity to charge a competitive toll depends on the overall demand for transportation service. A decrease in the level of demand for our pipeline transportation services could adversely impact revenues, although overall utilization of our pipeline capacity continues to grow and warrant further investment and expansion.

Commodity prices

The cyclical supply and demand nature of commodities and related pricing can have a secondary impact on our business where our shippers may choose to accelerate or delay certain projects. This can impact the timing of demand for transportation services and/or new natural gas pipeline infrastructure. Disruptions in the energy supply chain can result in price volatility and a decline in natural gas prices that could impact our shippers' financial condition and their ability to meet their transportation service cost obligations.

Regulatory risk

Decisions and evolving policies by regulators and other government authorities, including changes in regulation, can impact the approval, timing, construction, operation and financial performance of our natural gas pipelines. There is a risk that decisions are delayed or are not favourable and could therefore adversely impact construction costs, in-service dates, anticipated revenues and the opportunity to further invest in our systems. There is also risk of a regulator disallowing recovery of a portion of our costs, now or at some point in the future.

The regulatory approval process for larger infrastructure projects, including the time it takes to receive a decision, could be delayed or lead to an unfavourable decision due to evolving public opinion and government policy related to natural gas pipeline infrastructure development. If regulatory decisions are subsequently challenged in courts, this could result in further impacts to project costs and schedule delays.

Increased scrutiny of construction and operations processes by the regulator or other enforcing agencies has the potential to delay construction, increase operating costs or require additional capital investment. There is a risk of an adverse impact to income if these costs are not fully recoverable and/or reduce the competitiveness of tolls charged to customers.

We continuously manage these risks by monitoring legislative and regulatory developments and decisions to determine the possible impact on our natural gas pipelines business and developing rate, facility and tariff applications that account for and mitigate these risks where possible.

Governmental risk

Shifts in government policy or changes in government can impact our business. More complex regulatory processes, broader consultation requirements, more restrictive emissions and/or carbon pricing policies and changes to environmental regulations can impact our operations and opportunities for continued growth. We are committed to working with all levels of government to ensure our business benefits and risks are understood and mitigation strategies are implemented.

Construction and operations

Constructing and operating our pipelines to ensure transportation services are provided safely and reliably is essential to the success of our business. Interruptions in our pipeline operations impacting throughput capacity may result in reduced revenues and can affect corporate reputation, as well as customer and public confidence in our operations. We manage this by investing in a highly skilled workforce, hiring third-party inspectors during construction, operating prudently, monitoring our pipeline systems continuously, using risk-based preventive maintenance programs and making effective capital investments. We use pipeline inspection equipment to regularly check the integrity of our pipelines and repair or replace sections when necessary. We also calibrate meters regularly to ensure accuracy and employ robust reliability and integrity programs to maintain compression equipment and safe and reliable operations.

Power and Energy Solutions

The Power and Energy Solutions business consists of power generation, non-regulated natural gas storage assets, as well as emerging technologies that can provide lower-carbon solutions for our customers and industry.

Our Power and Energy Solutions business includes approximately 4,650 MW of generation powered by nuclear, natural gas, wind and solar. These generation assets are generally supported by long-term contracts. Our Canadian power infrastructure assets are located in Alberta, Ontario, Québec and New Brunswick while our U.S. power infrastructure assets are located in Texas. Additionally, we have approximately 400 MW of PPAs in Canada and approximately 350 MW of PPAs in the U.S. from wind and solar facilities.

We also own and operate approximately 118 Bcf of non-regulated natural gas storage capacity in Alberta.

Strategy

Our strategy is to maximize the value of our existing portfolio through maintaining safety and operational excellence while enhancing the life cycle and reliability of our assets and expanding profit margins through cost efficiency and revenue enhancement. Our business is anchored by nuclear generation and designed for scalable, low-risk growth that adapts to evolving energy needs. By leveraging our expertise across natural gas and power, we capture additional value through commercial marketing and system optimization, while maximizing availability of our cogeneration fleet. In the long term, we believe there will be a growing need for a reliable supply of resources as the energy mix evolves. We are positioning ourselves to play an important role in decarbonizing energy sources and will continue to build expertise and capabilities in emerging technologies and markets that offer commercial frameworks consistent with TC Energy’s value proposition of low risk, solid growth and repeatable performance.

Recent highlights

- Bruce Power completed planned outages on Units 2 and 5 in 2025
- Bruce Power received verification of the Unit 5 MCR final cost and schedule estimate from the IESO on April 2, 2025.

UNDERSTANDING OUR POWER AND ENERGY SOLUTIONS BUSINESS

Canadian Power

Canadian Power Generation & Marketing

We own and operate approximately 1,200 MW of power supply in Canada, excluding our investment in Bruce Power. In Alberta we own five facilities: four natural gas-fired cogeneration and one solar. We exercise a disciplined operating strategy to maximize revenues. Our marketing group sells uncommitted power while also buying and selling power and natural gas to maximize earnings. To reduce commodity price exposure associated with uncontracted power, we sell a portion of this output in forward sales markets when acceptable contract terms are available while the remainder is retained to be sold in the spot market or under short-term forward arrangements. The objective of this strategy is to maintain adequate power supply to fulfill our sales obligations if we have unexpected plant outages and enable us to capture opportunities to increase earnings in periods of high spot prices.

Bruce Power

Bruce Power is a nuclear power generation facility located near Tiverton, Ontario and is comprised of eight nuclear units with a combined capacity of approximately 6,580 MW. Bruce Power leases the facilities from OPG, has no spent fuel risk and will return the facilities to OPG for decommissioning at the end of the lease. We have a 48.3 per cent equity interest in Bruce Power.

Results from Bruce Power will fluctuate primarily due to units being offline for the MCR program and the frequency, scope and duration of planned and unplanned maintenance outages.

Through a long-term agreement with the IESO, Bruce Power is progressing a series of incremental life-extension investments to extend the operating life of the facility to 2064. This agreement represents an extension and material amendment to the earlier agreement that led to the refurbishment of Units 1 and 2 at the site. Under the amended agreement, which took economic effect in 2016, Bruce Power began investing in life extension activities for Units 3 through 8 to support the long-term refurbishment programs, known as the Asset Management program. Investment in the Asset Management program is designed to result in near-term life extensions of each of the six units up to the planned major refurbishment outages and beyond. The Asset Management program includes the one-time refurbishment or replacement of systems, structures or components that are not within the scope of the MCR program, which focuses on the actual replacement of the key, life-limiting reactor components. The MCR program is designed to add at least 35 years of operational life to each of the six units.

The Unit 6 MCR, the first of the six-unit MCR life extension program, was completed in third quarter 2023. The Unit 3 MCR and Unit 4 MCR, which are the second and third unit in the MCR program, commenced in first quarter 2023 and 2025, with expected completion dates in 2026 and 2028, respectively. The Unit 5 MCR final cost and schedule estimate was verified by the IESO on April 2, 2025. The Unit 5 MCR is expected to commence in fourth quarter 2026 with a return to service in early 2030. Investments in the remaining two units' MCR programs are expected to continue through 2033. Future MCR investments will be subject to discrete decisions for each unit with specified off-ramps available for Bruce Power and the IESO.

Along with the MCR life extension program, Bruce Power’s Project 2030 has a goal of achieving site peak output (capability) of 7,000 MW by 2033 in support of the province of Ontario's climate change targets and future clean energy needs. Project 2030 is focused on continued asset optimization, innovation and leveraging new technology to increase site capability. Project 2030 is being implemented in three stages with the first two stages and Stage 3a fully approved for execution. The program commenced in 2019 with a site capability of 6,430 MW and closed out 2025 at approximately 6,580 MW; a net gain of approximately 150 MW. Upon completion of Stage 1, 2 and 3a, the site is projected to reach 6,840 MW. All three stages are being implemented in parallel to the MCR program.

As part of the life extension and refurbishment agreement, Bruce Power receives a uniform contract price for all units which includes certain flow-through items such as fuel and lease expense recovery. The contract also provides for payment if the IESO requests a reduction in Bruce Power’s generation to balance the supply of and demand for, electricity and/or manage other operating conditions of the Ontario power grid. The amount of the reduction is considered deemed generation, for which Bruce Power is paid the contract price.

The contract price is subject to adjustments for the return of and on capital invested at Bruce Power under the Asset Management and MCR programs, along with various other pricing adjustments that allow for a better matching of revenues and costs over the long term. As part of the amended agreement, Bruce Power is also required to share operating cost efficiencies with the IESO for better than planned performance. These efficiencies are reviewed every three years and paid out on a monthly basis over the subsequent three-year period. No operating cost efficiencies for the 2025 to 2027 period have been provided for at December 31, 2025 and no operating cost efficiencies were realized for the 2019 to 2024 period.

Bruce Power is a global supplier of Cobalt-60, a medical isotope used in the sterilization of medical equipment and to treat certain types of cancer. Cobalt-60 is produced during Bruce Power's generation of electricity, harvested during certain planned maintenance outages and provided for medical use in the treatment of brain tumours and breast cancer. In addition, Bruce Power harvests Lutetium-177, a medical isotope used in the treatment of prostate cancer and neuroendocrine tumours. Lutetium-177 is generated and harvested while Bruce Power is generating electricity. Isotope production includes a partnership with the Saugeen Ojibway Nation, on whose traditional territory the Bruce Power facilities are located. Furthermore, Bruce Power has committed to building a hot cell facility in Bruce County, for the purposes of streamlining the supply chain for the short-lived Lutetium-177 to ensure it reaches cancer patients around the world in a timely fashion.

Power Purchase Agreements
We have approximately 400 MW of wind and solar generation PPAs and associated environmental attributes in Alberta. These PPAs allow us to generate incremental earnings by offering renewable power products to our customers.

U.S. Power

Power Generation & Marketing
We own approximately 300 MW of wind generation located in Texas which operate in the Electric Reliability Council of Texas (ERCOT) and Southwest Power Pool (SPP) markets. A portion of this power generation is sold under a long-term, fixed price contract.

Our U.S. Power and emissions commercial trading and marketing business optimizes the value of our assets and leverages physical and financial products in the power and environmental markets with a focus on risk management.

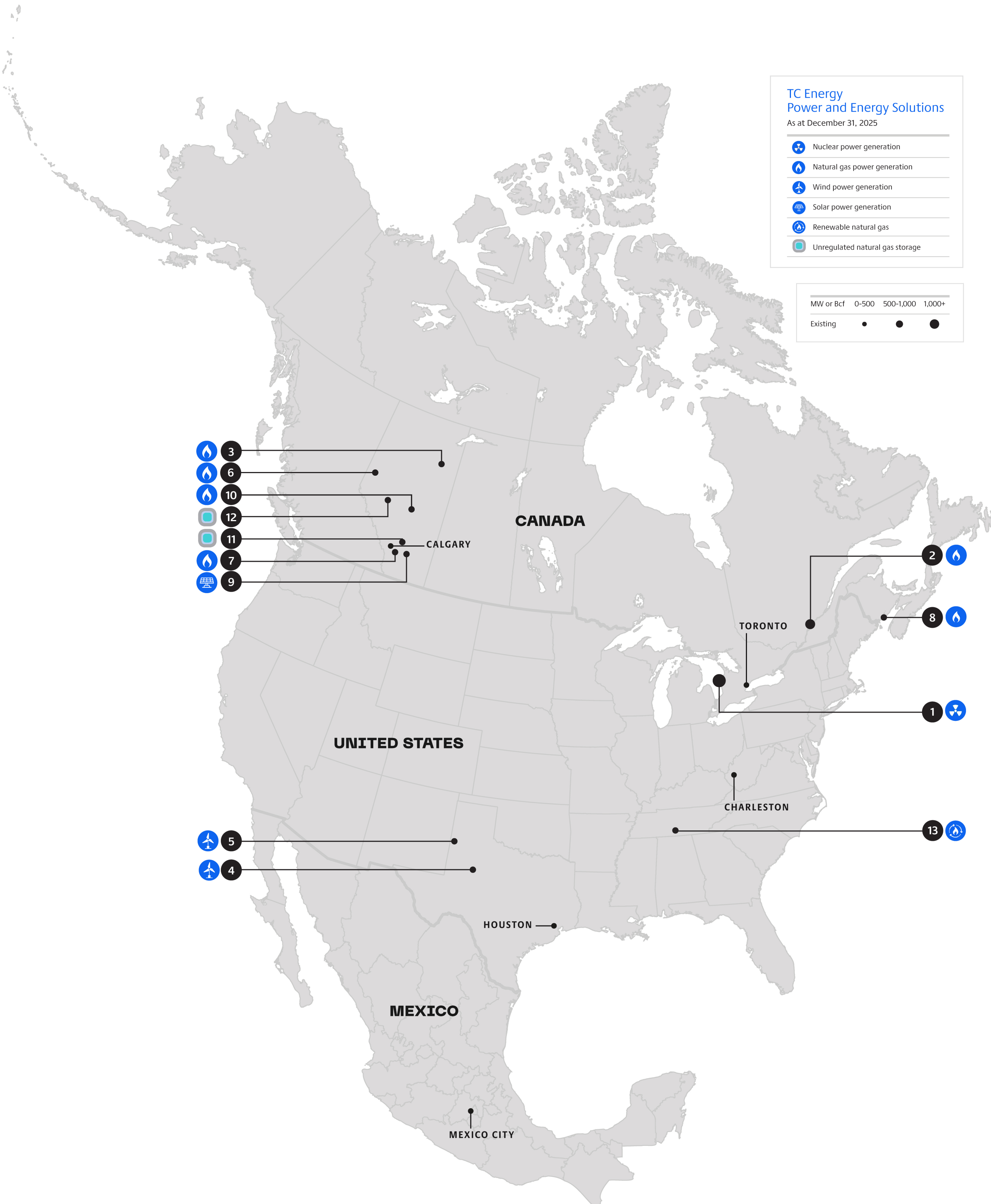
Power Purchase Agreements
We have approximately 350 MW of wind generation PPAs and associated environmental attributes in the U.S. These PPAs allow us to generate incremental earnings by offering renewable power products to our customers.

Other Energy Solutions

Canadian Natural Gas Storage
Our Canadian natural gas storage business helps balance seasonal and short-term supply and demand while also adding flexibility to the delivery of natural gas to markets in Alberta and the rest of North America. Market volatility creates arbitrage opportunities and our natural gas storage facilities also give us and our customers the ability to capture value from short-term price movements. The natural gas storage business is affected by changes in seasonal natural gas price spreads which are generally determined by the differential in natural gas prices between the traditional summer injection and winter withdrawal seasons. In addition, the business may be affected by pipeline restrictions in Alberta which limit the ability to capture price differentials.

Our natural gas storage business contracts with third parties, typically participants in the Alberta and interconnected gas markets, for a fixed fee to provide natural gas storage services on a short, medium and/or long-term basis.

We also enter proprietary natural gas storage transactions which include a forward purchase of our own natural gas to be injected into storage and a simultaneous forward sale of natural gas for withdrawal at a later period, typically during the winter withdrawal season. By matching purchase and sales volumes on a back-to-back basis, we lock in future positive margins, effectively eliminating our exposure to changes in natural gas prices for these transactions.



TC Energy
Power and Energy Solutions
As at December 31, 2025
Nuclear power generation
Natural gas power generation
Wind power generation
Solar power generation
Renewable natural gas
Unregulated natural gas storage
MW or Bcf
0-500
500-1,000
1,000+
Existing
CANADA
UNITED STATES
MEXICO
CALGARY
TORONTO
CHARLESTON
HOUSTON
MEXICO CITY
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12
13

Power and Energy Solutions assets currently have a combined power generation capacity, net to TC Energy, of 4,652 MW. We operate each facility except for Bruce Power.

		Generating capacity (MW)	Type of fuel	Description	Ownership
	Power assets				
1	Bruce Power[1]	3,180	nuclear	Eight operating reactors in Tiverton, Ontario. Bruce Power leases the nuclear facilities from OPG.	48.3%
2	Bécancour	550	natural gas	Cogeneration plant in Trois-Rivières, Québec. Power generation has been suspended since 2008 although we continue to receive PPA capacity payments while generation is suspended.	100%
3	Mackay River	207	natural gas	Cogeneration plant in Fort McMurray, Alberta.	100%
4	Fluvanna[2]	155	wind	Wind farm located near Scurry County, Texas.	100%
5	Blue Cloud[2]	148	wind	Wind farm located near Bailey County, Texas.	100%
6	Bear Creek	100	natural gas	Cogeneration plant in Grande Prairie, Alberta.	100%
7	Carseland	95	natural gas	Cogeneration plant in Carseland, Alberta.	100%
8	Grandview	90	natural gas	Cogeneration plant in Saint John, New Brunswick.	100%
9	Saddlebrook Solar	81	solar	Hybrid solar generation facility near Aldersyde, Alberta.	100%
10	Redwater	46	natural gas	Cogeneration plant in Redwater, Alberta.	100%
	Canadian non-regulated natural gas storage				
11	Crossfield	68 Bcf		Underground facility connected to the NGTL System near Crossfield, Alberta.	100%
12	Edson	50 Bcf		Underground facility connected to the NGTL System near Edson, Alberta.	100%
	Under construction				
	Other energy solutions				
13	Lynchburg		RNG	RNG production facility in Lynchburg, Tennessee.	30%

1 Our share of power generation capacity.

2 TC Energy owns 100 per cent of the Class B Membership Interests and has a tax equity investor that owns 100 per cent of the Class A Membership Interests, to which a percentage of earnings, tax attributes and cash flows are allocated under the provisions of each tax equity agreement.

SIGNIFICANT EVENTS

Bruce Power Life Extension

Bruce Power received verification of the Unit 5 MCR final cost and schedule estimate from the IESO on April 2, 2025. The Unit 5 MCR is expected to commence in fourth quarter 2026 with a return to service in early 2030.

FINANCIAL RESULTS

The following is a reconciliation of comparable EBITDA and comparable EBIT (our non-GAAP measures) to segmented earnings (losses) (the most directly comparable GAAP measure). Refer to page 22 for more information on non-GAAP measures we use.

year ended December 31 (millions of $)	**2025**	**2024**	**2023**
Bruce Power[1]	**733**	890	680
Canadian Power	**181**	273	334
Natural Gas Storage and other[2]	**94**	51	6
Comparable EBITDA	**1,008**	1,214	1,020
Depreciation and amortization	**(113)**	(101)	(92)
Comparable EBIT	**895**	1,113	928
Specific items:			
Power and Energy Solutions impairment charges	**(110)**	(36)	—
Bruce Power unrealized fair value adjustments	**30**	8	7
Risk management activities	**(42)**	17	69
Segmented earnings (losses)	**773**	1,102	1,004

1 Includes our share of equity income from Bruce Power.
2 Includes non-controlling interest in the Texas Wind Farms, which comprises Class A Membership Interests. Refer to the Corporate - Financial results section for additional information.

Power and Energy Solutions segmented earnings decreased by $329 million in 2025 compared to 2024 and increased by $98 million in 2024 compared to 2023 and included the following specific items, which have been excluded from our calculation of comparable EBITDA and comparable EBIT:

- a pre-tax impairment charge in 2025 of $110 million (2024 – $36 million) for certain Power and Energy Solutions projects following our decision to discontinue development along with updated forecast assumptions as we refocus our Power and Energy Solutions strategy
- our proportionate share of Bruce Power's unrealized gains and losses on funds invested for post-retirement benefits and risk management activities
- unrealized gains and losses from changes in the fair value of derivatives used to reduce commodity exposures.

Comparable EBITDA for Power and Energy Solutions decreased by $206 million in 2025 compared to 2024 primarily due to the net effect of:

- lower Bruce Power contributions from reduced generation, mainly attributable to the Unit 4 MCR and higher operating costs, partially offset by a higher contract price. Refer to the Bruce Power section for additional information
- decreased Canadian Power results primarily from lower realized power prices
- increased Natural Gas Storage and other contributions reflecting lower business development costs, partially offset by decreased realized Alberta natural gas storage spreads in first quarter 2025 and reduced contributions from our U.S. marketing business.

Comparable EBITDA for Power and Energy Solutions increased by $194 million in 2024 compared to 2023 primarily due to the net effect of:

- higher contributions from Bruce Power primarily due to higher generation resulting from fewer outage days in 2024 and a higher contract price, partially offset by increased operating expenses and higher depreciation expense. Additional financial and operating information on Bruce Power is provided below
- increased Natural Gas Storage and other results primarily due to higher realized Alberta natural gas storage spreads and higher contributions from our U.S. marketing business, partially offset by increased business development costs in 2024
- decreased Canadian Power financial results primarily from lower realized power prices, partially offset by lower natural gas fuel costs.

Depreciation and amortization

Depreciation and amortization increased by $12 million in 2025 compared to 2024 following the in-service of maintenance projects and increased by $9 million in 2024 compared to 2023 primarily due to the acquisition of the Texas Wind Farms in the first half of 2023.

Bruce Power results

Bruce Power results reflect our proportionate share. Comparable EBITDA and comparable EBIT are non-GAAP measures. Refer to page 22 for more information on non-GAAP measures we use. The following is our proportionate share of the components of comparable EBITDA and comparable EBIT.

year ended December 31 (millions of $, unless otherwise noted)	**2025**	**2024**	**2023**
Items included in comparable EBITDA and comparable EBIT are comprised of:			
Revenues[1]	**2,112**	2,242	1,941
Operating expenses	**(1,000)**	(984)	(917)
Depreciation and other	**(379)**	(368)	(344)
Comparable EBITDA and comparable EBIT[2]	**733**	890	680
Bruce Power – other information			
Plant availability[3,4]	**91%**	92%	92%
Planned outage days[4]	**152**	160	106
Unplanned outage days	**44**	32	62
Sales volumes (GWh)[5]	**19,126**	22,209	20,447
Realized power price per MWh[6]	**$109**	$100	$94

1 Net of amounts recorded to reflect operating cost efficiencies shared with the IESO, if applicable.
2 Represents our 48.3 per cent ownership interest and internal costs supporting our investment in Bruce Power. Excludes unrealized gains and losses on funds invested for post-retirement benefits and risk management activities.
3 The percentage of time the plant was available to generate power, regardless of whether it was running.
4 Excludes MCR outage days.
5 Sales volumes include deemed generation, if applicable.
6 Calculation based on actual and deemed generation. Realized power price per MWh includes realized gains and losses from contracting activities and cost flow-through items. Excludes unrealized gains and losses on contracting activities and non-electricity revenues.

Planned maintenance in 2025 was completed on Unit 5 in first quarter and on Unit 2 in fourth quarter. Planned maintenance in 2024 was completed in second quarter on Units 5 to 8. A planned outage on Unit 4 was completed in second quarter 2023 and on Unit 8 in fourth quarter 2023.

On January 31, 2025, Unit 4 was removed from service to commence its MCR program, with a return to service expected in 2028.

OUTLOOK

Comparable EBITDA

Power and Energy Solutions comparable EBITDA in 2026 is expected to be higher than 2025 primarily due to increased Bruce Power equity income with the expected return to service of Unit 3 in early third quarter 2026 following its MCR outage, a higher contract price, and a reduction in non-MCR planned outage days. These positive factors are expected to be partially offset by the commencement of the Unit 5 MCR outage in fourth quarter 2026. Contributions from Canadian Power are expected to be lower due to decreased generation and higher natural gas prices, partially offset by increased Alberta power prices. Natural Gas Storage and other earnings are expected to be consistent with 2025.

Planned maintenance at Bruce Power in 2026 is scheduled on Unit 8 in the first quarter and on Unit 1 in the third quarter. Excluding the MCR programs for Units 3, 4, and 5, average plant availability for 2026 is expected to be in the low-90 per cent range.

Capital expenditures

We incurred $0.9 billion of capital expenditures in 2025, primarily for our share of Bruce Power's Unit 3 and 4 MCR and Asset Management programs, along with maintenance capital projects across the segment. For 2026, we expect a similar level of capital investment, approximately $1.0 billion, mainly allocated to our share of Bruce Power's Unit 4 and Unit 5 MCR and Asset Management programs.

BUSINESS RISKS

The following are risks specific to our Power and Energy Solutions business. Refer to page 94 for information about general risks related to TC Energy as a whole, including other operational, safety and financial risks, as well as our approach to risk management.

Fluctuating power and natural gas market prices

Much of the physical power generation and fuel used in our power operations is currently exposed to commodity price volatility. These exposures are partially mitigated through long-term contracts and hedging activities including selling and purchasing power and natural gas in forward markets. As contracts expire, new contracts are entered into at prevailing market prices.

Our two eastern Canadian natural gas-fired assets are fully contracted and not materially impacted by fluctuating spot power and natural gas prices. As the contracts on these assets expire it is uncertain if we will be able to re-contract on similar terms and may face future commodity exposure.

Our natural gas storage business is subject to fluctuating seasonal natural gas price spreads which are generally determined by the differential in natural gas prices between the traditional summer injection and winter withdrawal seasons. In addition, the business may be affected by pipeline restrictions in Alberta which limit the ability to capture price differentials.

Plant availability

Operating our plants to ensure services are provided safely and reliably as well as optimizing and maintaining their availability are essential to the continued success of our Power and Energy Solutions business. Unexpected outages or extended planned outages at our power plants can increase maintenance costs as well as lower plant output, revenues and margins. We may also have to buy power or natural gas on the spot market to meet our delivery obligations. We manage this risk by investing in a highly skilled workforce, operating prudently, running comprehensive risk-based preventive maintenance programs and making effective capital investments.

Regulatory

We operate in Canada and the U.S. in both regulated and deregulated power markets. These markets are subject to various federal, provincial and state regulations. As power markets evolve, there is the potential for regulatory bodies to implement new rules that could negatively affect us as a generator and marketer of electricity. These may be in the form of market rule or market design changes, changes in the interpretation and application of market rules by regulators, price caps, emission controls, emissions costs, cost allocations to generators and out-of-market actions taken by others to build excess generation, all of which may negatively affect the price of power. In addition, our development projects rely on an orderly permitting process and any disruption to that process can have negative effects on project schedules and costs. We are an active participant in formal and informal regulatory proceedings and take legal action where required.

Compliance

Market rules, regulations and operating standards apply to our power business based on the jurisdictions in which they operate. Our trading and marketing activities may be subject to fair competition and market conduct requirements as well as specific rules that apply to physical and financial transactions in deregulated markets. Similarly, our generators may be subject to specific operating and technical standards relating to maintenance activities, generator availability and delivery of power and power-related products. While significant efforts are made to ensure we comply with all applicable statutory requirements, situations including unforeseen operational challenges, lack of rule clarity and the ambiguous and unpredictable application of requirements by regulators and market monitors occasionally arise and create compliance risk. Deemed contravention of these requirements may result in mandatory mitigation activities, monetary penalties, imposition of operational limitations, or even prosecution.

Weather

Significant changes in temperature and weather, including the potential impacts of climate change, have many effects on our business, ranging from the impact on demand, availability and commodity prices, to efficiency and output capability. Extreme temperature and weather can affect market demand for power and natural gas and can lead to significant price volatility, as well as restrict the availability of natural gas and power if demand is higher than supply. Fluctuations in seasonal weather patterns or temperature can affect the efficiency and production of our natural gas-fired power plants.

Competition

We face various competitive forces that impact our existing assets and prospects for growth. For instance, our existing power plants will compete over time with new power capacity. New supply could come in several forms including supply that employs more efficient power generation technologies or additional supply from regional power transmission interconnections. We also face competition from other power companies in Canada and the U.S., as well as in the development of greenfield power plants. Traditional and non-traditional participants are entering the growing lower-carbon economy in North America and, as a result, we face competition in building lower-carbon energy solutions.

Execution and capital costs

We make substantial capital commitments developing power generation infrastructure based on the assumption that these assets will deliver an attractive return on investment. While we carefully consider the scope and expected costs of our capital projects, we are exposed to execution and capital cost overrun risk which may impact our return on these projects. We mitigate this risk by implementing comprehensive project governance and oversight processes and through the structuring of engineering, procurement and construction contracts with reputable counterparties.

Corporate

SIGNIFICANT EVENTS

2016 Columbia Pipeline Acquisition Lawsuit

In 2018, former shareholders of Columbia Pipeline Group Inc. (CPG) commenced a class action lawsuit related to the acquisition of CPG by TC Energy in 2016. In 2023, the Delaware Chancery Court (the Court) found that the former CPG executives breached their fiduciary duties, that the former CPG Board breached its duty of care in overseeing the sale process and that TC Energy aided and abetted those breaches. TC Energy's allocated share of damages was an estimated US$350 million, plus post-judgment interest. TC Energy appealed the decision to the Delaware Supreme Court and on June 17, 2025, the Supreme Court issued its decision reversing the Court's finding of liability against TC Energy. On July 10, 2025, the Court granted the final order vacating its prior judgment and dismissing plaintiffs' claims against TC Energy. As a result, this matter is now concluded in TC Energy's favour with no liability. There is no further right of appeal.

FINANCIAL RESULTS

The following is a reconciliation of comparable EBITDA and comparable EBIT (our non-GAAP measures) to segmented earnings (losses) (the most directly comparable GAAP measure). Refer to page 22 for more information on non-GAAP measures we use.

year ended December 31 (millions of $)	2025	2024	2023
Comparable EBITDA	**(14)**	(63)	(73)
Depreciation and amortization	**—**	(5)	(6)
Comparable EBIT	**(14)**	(68)	(79)
Specific items:			
Third-party settlement	**—**	(34)	—
Focus Project costs	**—**	(24)	(65)
NGTL System ownership transfer costs	**—**	(10)	—
Segmented earnings (losses)	**(14)**	(136)	(144)

In 2025, Corporate segmented losses were $14 million compared to $136 million and $144 million in 2024 and 2023, respectively, and included the following specific items which have been excluded from our calculation of comparable EBITDA and comparable EBIT:

- a pre-tax expense of $34 million (US$25 million) in 2024 related to a non-recurring third-party settlement
- a pre-tax charge of $24 million recorded in 2024 (2023 – $65 million) related to Focus Project costs
- a pre-tax charge of $10 million in 2024 related to the NGTL System ownership transfer.

Comparable EBITDA for Corporate included shared costs in 2024 and 2023 related to TC Energy's corporate services and governance functions that were not allocated to discontinued operations in accordance with U.S. GAAP.

Depreciation and amortization

Depreciation and amortization for 2024 and 2023 included depreciation related to TC Energy's corporate services and governance functions that were not allocated to discontinued operations in accordance with U.S. GAAP.

OTHER INCOME STATEMENT ITEMS

Interest expense

year ended December 31 (millions of $)	2025	2024	2023
Interest expense on long-term debt and junior subordinated notes			
Canadian dollar-denominated	**(816)**	(856)	(895)
U.S. dollar-denominated	**(1,716)**	(1,855)	(1,692)
Foreign exchange impact	**(683)**	(685)	(592)
	(3,215)	(3,396)	(3,179)
Other interest and amortization expense	**(204)**	(147)	(261)
Capitalized interest	**10**	191	187
Interest expense allocated to discontinued operations	**—**	176	287
Interest expense included in comparable earnings	**(3,409)**	(3,176)	(2,966)
Specific items:			
Net gain on debt extinguishment	**—**	228	—
Risk management activities	**2**	(71)	—
Interest expense	**(3,407)**	(3,019)	(2,966)

Interest expense increased by $388 million in 2025 compared to 2024 and increased by $53 million in 2024 compared to 2023. The following specific items have been removed from our calculation of interest expense included in comparable earnings:

- pre-tax net gain on debt extinguishment of $228 million was recorded related to the purchase and cancellation of certain senior unsecured notes and medium term notes and the retirement of outstanding callable notes in October 2024
- unrealized gains and losses on derivatives used to manage our interest rate risk. Refer to the Other information - Financial risks and financial instruments sections for additional information.

Interest expense included in comparable earnings in 2025 increased by $233 million compared to 2024 primarily due to the net effect of:

- lower capitalized interest due to the declared commercial in-service of the Coastal GasLink pipeline in fourth quarter 2024
- no interest expense allocated to discontinued operations in 2025
- long-term debt issuances and maturities, including lower interest expense resulting from TCPL's cash tender offers completed in fourth quarter 2024
- increased levels of short-term borrowing.

Interest expense included in comparable earnings in 2024 increased by $210 million compared to 2023 mainly due to the net effect of:

- long-term debt issuances and maturities
- interest expense allocated to discontinued operations for nine months in 2024 compared to a full year in 2023. Refer to the Discontinued operations section for additional information
- the foreign exchange impact from a weaker U.S. dollar on translation of U.S. dollar-denominated interest expense
- reduced levels of short-term borrowing.

Refer to the Financial condition section for additional information.

Allowance for funds used during construction

year ended December 31 (millions of $)	2025	2024	2023
Canadian dollar-denominated	**51**	34	102
U.S. dollar-denominated	**284**	546	350
Foreign exchange impact	**118**	204	123
Allowance for funds used during construction	**453**	784	575

AFUDC decreased by $331 million in 2025 compared to 2024. The increase in Canadian dollar-denominated AFUDC is primarily related to NGTL System expansion projects. The decrease in U.S. dollar-denominated AFUDC is primarily due to the completion of the Southeast Gateway pipeline in second quarter 2025 and the suspension of AFUDC on the south section of the Villa de Reyes pipeline in first quarter 2025 due to ongoing construction delays on the project pending the resolution of outstanding stakeholder issues, partially offset by capital expenditures on our U.S. natural gas pipeline projects.

AFUDC increased by $209 million in 2024 compared to 2023. The decrease in Canadian dollar-denominated AFUDC is primarily related to NGTL System expansion projects placed in service in 2024. The increase in U.S. dollar-denominated AFUDC is primarily due to capital expenditures on the Southeast Gateway pipeline project and U.S. natural gas pipeline projects in 2024, partially offset by the suspension of AFUDC on the assets under construction for the Tula pipeline project due to the delay of an FID and placing the lateral section of Villa de Reyes pipeline in service in August 2023.

Foreign exchange gains (losses), net

year ended December 31 (millions of $)	2025	2024	2023
Foreign exchange gains (losses), net included in comparable earnings	**96**	(85)	118
Specific items:			
Foreign exchange gains (losses), net – intercompany loan[1]	**(149)**	204	(44)
Risk management activities	**210**	(266)	246
Foreign exchange gains (losses), net	**157**	(147)	320

1 Includes non-controlling interest. Refer to Net (income) loss attributable to non-controlling interests for additional information.

Foreign exchange gains (losses), net, in 2025 changed by $304 million compared to 2024 and changed by $467 million in 2024 compared to 2023. The following specific items have been removed from our calculation of Foreign exchange gains (losses), net included in comparable earnings:

- unrealized foreign exchange gains and losses on the peso-denominated intercompany loan between TCPL and TGNH beginning in second quarter 2023
- unrealized gains and losses from changes in the fair value of derivatives used to manage our foreign exchange risk. Refer to the Other information – Financial risks and Financial instruments sections for additional information.

Foreign exchange gains (losses), net included in comparable earnings in 2025 changed by $181 million compared to 2024. The change was primarily due to the net effect of:

- risk management activities used to manage our foreign exchange exposure to net liabilities in Mexico and to U.S. dollar-denominated income
- foreign exchange losses in 2025 compared to foreign exchange gains in 2024 on the revaluation of our peso-denominated net monetary liabilities to U.S. dollars
- a net realized gain in second quarter 2024 on the partial repayment of the peso-denominated intercompany loan between TCPL and TGNH.

Foreign exchange gains (losses), net included in comparable earnings in 2024 changed by $203 million compared to 2023. The change was primarily due to the net effect of:

- risk management activities used to manage our foreign exchange exposure to net liabilities in Mexico and to U.S. dollar-denominated income
- foreign exchange gains in 2024 compared to foreign exchange losses in 2023 on the revaluation of our peso-denominated net monetary liabilities to U.S. dollars
- a net realized gain in second quarter 2024 on the partial repayment of the peso-denominated intercompany loan between TCPL and TGNH.

Interest income and other

year ended December 31 (millions of $)	2025	2024	2023
Canadian dollar-denominated	**49**	87	62
U.S. dollar-denominated	**112**	172	156
Foreign exchange impact	**44**	65	54
Interest income and other	**205**	324	272

Interest income and other decreased by $119 million in 2025 compared to 2024 primarily due to the net effect of:

- lower interest earned on Canadian and U.S. dollar-denominated short-term investments
- increased insurance-related provisions
- higher investment income and the change in fair value of other restricted investments.

Interest income and other increased by $52 million in 2024 compared to 2023 primarily due to the net effect of:

- higher interest earned on Canadian dollar-denominated short-term investments
- decreased insurance-related provisions.

Income tax (expense) recovery

year ended December 31 (millions of $)	2025	2024	2023
Income tax (expense) recovery included in comparable earnings	**(1,112)**	(772)	(890)
Specific items:			
Power and Energy Solutions impairment charges	**25**	9	—
Foreign exchange gains (losses), net – intercompany loan	**(13)**	10	—
Expected credit loss provision on net investment in leases and certain contract assets in Mexico	**24**	(7)	(25)
Gain on sale of PNGTS	**—**	(116)	—
Revaluation of deferred tax balances	**—**	(96)	—
Net gain on debt extinguishment	**—**	(50)	—
Gain on sale of non-core assets	**—**	15	—
Third-party settlement	**—**	8	—
Focus Project costs	**—**	6	17
NGTL System ownership transfer costs	**—**	(32)	—
Coastal GasLink impairment charge	**—**	—	157
Bruce Power unrealized fair value adjustments	**(7)**	(2)	(2)
Risk management activities	**(55)**	105	(99)
Income tax (expense) recovery	**(1,138)**	(922)	(842)

Income tax expense in 2025 increased by $216 million compared to 2024 and increased by $80 million in 2024 compared to 2023.

In addition to the income tax impacts on other specific items referenced elsewhere in this MD&A, Income tax (expense) recovery also includes the following specific items, which have been removed from our calculation of Income tax (expense) recovery included in comparable earnings:

2024

- a deferred income tax expense of $96 million resulting from the revaluation of remaining deferred tax balances following the Spinoff Transaction.

2023

- a $157 million income tax recovery related to the impairment of our equity investment in Coastal GasLink LP.

Income tax expense included in comparable earnings in 2025 increased by $340 million compared to 2024 primarily due to Mexico foreign exchange exposure and higher flow-through income taxes.

Income tax expense included in comparable earnings in 2024 decreased by $118 million compared to 2023 primarily due to Mexico foreign exchange exposure and lower earnings subject to income tax, partially offset by lower foreign income tax rate differentials and higher flow-through income taxes.

Refer to the Foreign exchange section for additional information on our Mexico foreign exchange exposure.

Net (income) loss attributable to non-controlling interests

year ended December 31 (millions of $)	Non-Controlling Interests Ownership at December 31, 2025	2025	2024	2023
Columbia Gas and Columbia Gulf[1]	40%	**(631)**	(571)	(143)
TGNH[2]	13.01%	**(50)**	(48)	—
Texas Wind Farms[3]	100%	**38**	29	38
PNGTS[4]	nil	**—**	(30)	(41)
Net (income) loss attributable to non-controlling interests included in comparable earnings		**(643)**	(620)	(146)
Specific item:				
Foreign exchange (gains) losses, net – intercompany loan		**60**	(61)	—
Expected credit loss provision on net investment in leases		**8**	—	—
Net (income) loss attributable to non-controlling interests		**(575)**	(681)	(146)

1 In October 2023, we completed the sale of a 40 per cent non-controlling equity interest in Columbia Gas and Columbia Gulf to Global Infrastructure Partners.

2 In second quarter 2024, the CFE became a partner in TGNH with a 13.01 per cent equity interest in TGNH. Refer to the Mexico Natural Gas Pipelines – Significant events section for additional information.

3 Tax equity investors own 100 per cent of the Class A Membership Interests, to which a percentage of earnings, tax attributes and cash flows are allocated. We own 100 per cent of the Class B Membership Interests.

4 The sale of PNGTS was completed in August 2024.

Net income attributable to non-controlling interests decreased by $106 million in 2025 compared to 2024 and increased by $535 million in 2024 compared to 2023 and included the following specific items which have been excluded from our calculation of Net (income) loss attributable to non-controlling interests included in comparable earnings:

- the non-controlling interest portion of the unrealized foreign exchange gains and losses on the TGNH peso-denominated intercompany loan payable to TCPL
- the expected credit loss provision related to the TGNH net investment in leases.

Net income attributable to non-controlling interests included in comparable earnings increased by $23 million in 2025 compared to 2024. The increase is primarily due to higher net income recognized from the Columbia Gas and Columbia Gulf assets, the net impact of higher EBITDA and lower AFUDC in TGNH following the Southeast Gateway pipeline's completion in second quarter 2025, the full year impact of the 13.01 per cent TGNH non-controlling equity interest sale to the CFE, which was completed in second quarter 2024 and the overall impact of foreign exchange. This was partially offset by the divestiture of PNGTS in third quarter 2024.

Net income attributable to non-controlling interests included in comparable earnings increased by $474 million in 2024 compared to 2023 primarily due to the sale of a 40 per cent non-controlling equity interest in Columbia Gas and Columbia Gulf to Global Infrastructure Partners in fourth quarter 2023 and the 13.01 per cent non-controlling equity interest in TGNH to the CFE, which was completed in second quarter 2024.

Preferred share dividends

year ended December 31 (millions of $)	2025	2024	2023
Preferred share dividends	**(119)**	(104)	(93)

Preferred share dividends increased by $15 million in 2025 compared to 2024 and increased by $11 million in 2024 compared to 2023 primarily due to the redemption of preferred shares in 2025, dividend rate resets on and conversions of certain series of preferred shares in 2025 and 2024. Refer to Note 24, Preferred shares, of our 2025 Consolidated financial statements for additional information.

Foreign exchange

Foreign exchange related to U.S. dollar-denominated operations

Certain of our businesses generate all or most of their earnings in U.S. dollars and since we report our financial results in Canadian dollars, changes in the value of the U.S. dollar against the Canadian dollar directly affect our comparable EBITDA and may also impact comparable earnings. As our U.S. dollar-denominated operations continue to grow, this exposure increases. A portion of the U.S. dollar-denominated comparable EBITDA exposure is naturally offset by U.S. dollar-denominated amounts below comparable EBITDA within Depreciation and amortization, Interest expense and other income statement line items. A portion of the remaining exposure is actively managed on a rolling forward basis up to three years using foreign exchange derivatives; however, the natural exposure beyond that period remains. The net impact of the U.S. dollar movements on comparable earnings during the year ended December 31, 2025, after considering natural offsets and economic hedges, was not significant.

The components of our financial results denominated in U.S. dollars are set out in the table below, including our U.S. Natural Gas Pipelines and Mexico Natural Gas Pipelines operations. Comparable EBITDA is a non-GAAP measure.

Pre-tax U.S. dollar-denominated income and expense items - from continuing operations

year ended December 31 (millions of US$)	2025	2024	2023
Comparable EBITDA			
U.S. Natural Gas Pipelines	**3,506**	3,294	3,248
Mexico Natural Gas Pipelines	**981**	730	596
	4,487	4,024	3,844
Depreciation and amortization	**(812)**	(764)	(758)
Interest expense on long-term debt and junior subordinated notes	**(1,716)**	(1,855)	(1,692)
Interest income and other	**112**	172	156
Interest expense allocated to discontinued operations	**—**	125	189
Allowance for funds used during construction	**284**	546	350
Net (income) loss attributable to non-controlling interests included in comparable earnings and other	**(466)**	(481)	(156)
	1,889	1,767	1,933
Average exchange rate – U.S. to Canadian dollars	**1.40**	1.37	1.35

Foreign exchange related to Mexico Natural Gas Pipelines

Changes in the value of the Mexican peso against the U.S. dollar can affect our comparable earnings as a portion of our Mexico Natural Gas Pipelines' monetary assets and liabilities are peso-denominated, while our financial results are denominated in U.S. dollars for our Mexico operations. These peso-denominated balances are revalued to U.S. dollars, creating foreign exchange gains and losses that are included in Income (loss) from equity investments, Foreign exchange (gains) losses, net and Net income (loss) attributable to non-controlling interests in the Consolidated statement of income.

In addition, foreign exchange gains or losses calculated for Mexico income tax purposes on the revaluation of U.S. dollar-denominated monetary assets and liabilities result in a peso-denominated income tax exposure for these entities, leading to fluctuations in Income from equity investments and Income tax expense. This exposure increases as our U.S. dollar-denominated net monetary liabilities grow.

The above exposures are managed using foreign exchange derivatives, although some unhedged exposure remains. The impacts of the foreign exchange derivatives are recorded in Foreign exchange (gains) losses, net in the Consolidated statement of income. Refer to the Other information – Financial risks and Financial instruments sections for additional information.

The period end exchange rates for one U.S. dollar to Mexican pesos were as follows:

December 31, 2025	**18.00**
December 31, 2024	20.87
December 31, 2023	16.91

A summary of the impacts of transactional foreign exchange gains and losses from changes in the value of the Mexican peso against the U.S. dollar and associated derivatives is set out in the table below:

year ended December 31 (millions of $)	**2025**	**2024**	**2023**
Comparable EBITDA – Mexico Natural Gas Pipelines[1]	**(80)**	115	(83)
Foreign exchange gains (losses), net included in comparable earnings	**140**	(53)	224
Income tax (expense) recovery included in comparable earnings	**(89)**	110	(133)
Net (income) loss attributable to non-controlling interests included in comparable earnings[2]	**7**	(11)	—
	(22)	161	8

1 Includes the foreign exchange impacts from the Sur de Texas joint venture recorded in Income (loss) from equity investments in the Consolidated statement of income.

2 Represents the non-controlling interest portion related to TGNH. Refer to the Corporate - Financial results section for additional information.

Financial condition

We strive to maintain financial strength and flexibility in all parts of the economic cycle. We rely on our operating cash flows to sustain our business, pay dividends and fund a portion of our growth. In addition, we access capital markets and engage in portfolio management activities to meet our financing needs and to manage our capital structure and credit ratings. More information on how our credit ratings can impact our financing costs, liquidity and operations is available in our Annual Information Form available on SEDAR+ (www.sedarplus.ca).

We believe we have the financial capacity to fund our existing capital program through predictable and growing cash flows from continuing operations, access to capital markets, portfolio management activities, joint ventures, asset-level financing, cash on hand and substantial committed credit facilities. Annually, in the fourth quarter, we renew and extend our credit facilities as required.

Financial Plan

Our capital program is comprised of approximately $21 billion of secured projects, as well as our projects under development, which are subject to key corporate and regulatory approvals. As discussed throughout this Financial condition section, our capital program is expected to be financed through our growing internally-generated cash flows and a combination of other funding options which may include:

- senior debt
- hybrid securities
- preferred shares
- asset divestitures and capital rotation
- project financing
- potential involvement of strategic or financial partners.

In addition, we may access additional funding options, as deemed appropriate, including common shares issued from treasury under our DRP and discrete common equity issuances.

Balance sheet analysis - from continuing operations

At December 31, 2025, excluding discontinued operations, our current assets totaled $6.1 billion and current liabilities amounted to $9.8 billion, leaving us with a working capital deficit of $3.7 billion compared to $4.8 billion at December 31, 2024. Our working capital deficiency is considered to be in the normal course of business and is managed through:

- our ability to generate predictable and growing cash flows from operations
- a total of $7.8 billion of TCPL committed revolving credit facilities, of which $7.2 billion of short-term borrowing capacity remains available, net of $0.6 billion backstopping outstanding commercial paper balances, and arrangements for a further $2.0 billion of demand credit facilities, of which $1.3 billion remains available as of December 31, 2025
- additional $2.1 billion committed revolving credit facilities at certain of our subsidiaries and affiliates, of which $1.5 billion of short-term borrowing capacity remains available as of December 31, 2025, net of $0.6 billion backstopping outstanding commercial paper balances
- our access to capital markets, including through securities issuances, incremental credit facilities, capital rotation and DRP, if deemed appropriate.

Our total assets from continuing operations at December 31, 2025 were $118.6 billion compared to $117.9 billion at December 31, 2024 reflecting our 2025 capital spending program, equity investments and working capital, partially offset by a weaker U.S. dollar at December 31, 2025 compared to December 31, 2024 on translation of our U.S. dollar-denominated assets.

At December 31, 2025 our total liabilities from continuing operations were $81.7 billion, compared to $79.6 billion at December 31, 2024 due to the net effect of movements in debt, working capital and a weaker U.S. dollar at December 31, 2025 compared to December 31, 2024 on translation of our U.S. dollar-denominated liabilities.

Consolidated capital structure - from continuing operations

The following table summarizes the components of our capital structure for continuing operations.

at December 31 (millions of $, unless otherwise noted)	2025	Percentage of total	2024	Percentage of total
Notes payable	**1,200**	**2 %**	387	1 %
Long-term debt, including current portion	**46,792**	**48 %**	47,931	49 %
Cash and cash equivalents	**(168)**	**—**	(801)	(1)%
	47,824	**50 %**	47,517	49 %
Junior subordinated notes	**12,094**	**12 %**	11,048	11 %
Preferred shares	**2,255**	**2 %**	2,499	3 %
Common shareholders' equity	**25,040**	**26 %**	25,093	26 %
Non-controlling interests	**9,604**	**10 %**	10,768	11 %
	96,817	**100 %**	96,925	100 %

Provisions of various trust indentures, credit arrangements and other agreements with certain of our subsidiaries can restrict those subsidiaries' ability and, in certain cases, our ability to declare and pay dividends or make distributions under certain circumstances. In the opinion of management, these provisions do not currently restrict our ability to declare or pay dividends. These trust indentures and credit arrangements also require us to comply with various affirmative and negative covenants and maintain certain financial ratios. We were in compliance with all of our financial covenants at December 31, 2025.

Cash flows[1,2]

The following tables summarize our consolidated cash flows.

year ended December 31 (millions of $)	2025	2024	2023
Net cash provided by operations	**7,346**	7,696	7,268
Net cash (used in) provided by investing activities	**(6,458)**	(6,909)	(12,287)
Net cash (used in) provided by financing activities	**(1,516)**	(3,874)	8,093
	(628)	(3,087)	3,074
Effect of foreign exchange rate changes on cash and cash equivalents	**(5)**	210	(16)
Increase (decrease) in cash and cash equivalents	**(633)**	(2,877)	3,058

1 Includes continuing and discontinued operations.

2 Includes nine months of Liquids Pipelines earnings in 2024 and a full year of earnings in 2023. Refer to the Discontinued operations section for additional information.

Cash provided by operating activities[1,2]

year ended December 31 (millions of $)	2025	2024	2023
Net cash provided by operations	**7,346**	7,696	7,268
Increase (decrease) in operating working capital	**503**	(199)	(207)
Funds generated from operations	**7,849**	7,497	7,061
Specific items:			
South Bow settlement	**147**	—	—
Liquids Pipelines business separation costs, net of current income tax	**—**	185	40
Current income tax (recovery) expense on sale of PNGTS and non-core assets	**—**	148	—
Third-party settlement, net of current income tax	**—**	26	—
Focus Project costs, net of current income tax	**—**	21	54
NGTL System ownership transfer costs	**—**	10	—
Current income tax (recovery) expense on risk management activities	**—**	9	—
Current income tax (recovery) expense on Keystone XL asset impairment charge and other	**—**	(3)	(14)
Current income tax (recovery) expense on Keystone regulatory decisions	**—**	(3)	53
Current income tax (recovery) expense on disposition of equity interest[3]	**—**	—	736
Milepost 14 insurance expense	**—**	—	36
Keystone XL preservation and other, net of current income tax	**—**	—	14
Comparable funds generated from operations	**7,996**	7,890	7,980

1 Includes continuing and discontinued operations.
2 Includes nine months of Liquids Pipelines earnings in 2024 and a full year of earnings in 2023. Refer to the Discontinued operations section for additional information.
3 Current income tax expense related to applying an approximate 24 per cent tax rate to the tax gain on sale of a 40 per cent non-controlling equity interest in Columbia Gas and Columbia Gulf. This is offset by a corresponding deferred tax recovery resulting in no net impact to tax expense.

Net cash provided by operations

Net cash provided by operations decreased by $350 million in 2025 compared to 2024 primarily due to the timing of working capital changes, partially offset by higher funds generated from operations.

Net cash provided by operations increased by $428 million in 2024 compared to 2023 primarily due to higher funds generated from operations.

Comparable funds generated from operations

Comparable funds generated from operations, a non-GAAP measure, helps us assess the cash generating ability of our businesses by excluding the timing effects of working capital changes, as well as the cash impact of our specific items.

Comparable funds generated from operations increased by $106 million in 2025 compared to 2024 primarily due to higher comparable EBITDA and risk management activities used to manage our foreign exchange exposure to net liabilities in Mexico and to U.S. dollar-denominated income, partially offset by lower distributions from our equity investments.

Comparable funds generated from operations decreased by $90 million in 2024 compared to 2023 primarily due to lower comparable earnings, partially offset by increased distributions from our equity investments.

Cash (used in) provided by investing activities[1]

year ended December 31 (millions of $)	2025	2024	2023
Capital spending[2]			
Capital expenditures	**(5,270)**	(6,308)	(8,007)
Capital projects in development	**(16)**	(50)	(142)
Contributions to equity investments	**(1,051)**	(1,546)	(4,149)
	(6,337)	(7,904)	(12,298)
Other distributions from equity investments	**5**	549	23
Proceeds from sales of assets, net of transaction costs	**—**	791	33
Acquisitions, net of cash acquired	**—**	—	(307)
Loans to affiliate (issued) repaid, net	**—**	—	250
Deferred amounts and other	**(126)**	(345)	12
Net cash (used in) provided by investing activities	**(6,458)**	(6,909)	(12,287)

1 Includes continuing and discontinued operations.

2 Capital spending reflects cash flows associated with our Capital expenditures, Capital projects in development and Contributions to equity investments. For the year ended December 31, 2024, Contributions to equity investments were net of Other distributions from equity investments of $3.1 billion in the Canadian Natural Gas Pipelines segment. Refer to Note 5, Segmented information, Note 10, Equity investments and Note 11, Loans with affiliates, of our 2025 Consolidated financial statements for additional information.

Net cash used in investing activities decreased from $6.9 billion in 2024 to $6.5 billion in 2025 primarily as a result of decreased capital spending in 2025, partially offset by proceeds from sale of assets in 2024.

Net cash used in investing activities decreased from $12.3 billion in 2023 to $6.9 billion in 2024 primarily as a result of decreased capital spending and lower contributions to equity investments primarily related to Coastal GasLink LP and in part by higher proceeds from the sales of assets and distributions from equity investments.

Capital spending[1]

The following table summarizes capital spending by segment.

year ended December 31 (millions of $)	2025	2024	2023
Canadian Natural Gas Pipelines	**1,405**	2,100	6,184
U.S. Natural Gas Pipelines	**3,457**	2,575	2,660
Mexico Natural Gas Pipelines	**522**	2,228	2,292
Power and Energy Solutions	**922**	824	1,080
Corporate	**31**	50	33
	6,337	7,777	12,249
Discontinued operations	**—**	127	49
	6,337	7,904	12,298

1 Capital spending reflects cash flows associated with our Capital expenditures, Capital projects in development and Contributions to equity investments. For the year ended December 31, 2024, Contributions to equity investments were net of Other distributions from equity investments of $3.1 billion in the Canadian Natural Gas Pipelines segment. Refer to Note 5, Segmented information, Note 10, Equity investments and Note 11, Loans with affiliates, of our 2025 Consolidated financial statements for additional information.

Capital expenditures
Capital expenditures in 2025 were incurred primarily for the advancement of the Columbia Gas and ANR projects, the NGTL System expansion as well as maintenance capital expenditures. Lower capital expenditures in 2025 compared to 2024 reflect the completion of the Southeast Gateway pipeline in second quarter 2025, partially offset by increased spending on ANR projects.

Capital projects in development
Costs incurred during 2025 on Capital projects in development were attributable to spending on projects in the Power and Energy Solutions segment.

Contributions to equity investments
Contributions to equity investments decreased in 2025 compared to 2024 mainly due to lower funds advanced to Coastal GasLink LP through the subordinated loan agreement.

Contributions to equity investments decreased in 2024 compared to 2023 mainly due to lower funds advanced to Coastal GasLink LP through the subordinated loan agreement.

On December 17, 2024, following the declared commercial in-service of the pipeline, Coastal GasLink LP repaid the $3,147 million balance owing to us under the subordinated loan agreement. Our share of equity contributions required to fund Coastal GasLink LP's repayment of the outstanding loan balance amounted to $3,137 million. The Contributions to equity investments and Other distributions from equity investments with respect to these activities are presented above on a net basis, although they are reported on a gross basis in our Consolidated statement of cash flows. Refer to Note 11, Loans with affiliates, of our 2025 Consolidated financial statements for additional information.

Other distributions from equity investments
Other distributions from equity investments decreased in 2025 compared to 2024 mainly due to distributions from Millennium as a result of its debt financing program in 2024, as well as lower return of capital from our equity investment in Iroquois.

Other distributions from equity investments increased in 2024 compared to 2023 mainly due to distributions from Millennium as a result of its debt financing program in 2024.

Proceeds from sales of assets
In 2024, TC Energy and its partner, Northern New England Investment Company, Inc., a subsidiary of Énergir, completed the sale of PNGTS to a third party. Our share of the proceeds was $743 million (US$546 million), net of transaction costs.

In 2024, we also completed the sale of other non-core assets for gross proceeds of $48 million.

In 2023, we completed the sale of a 20.1 per cent equity interest in Port Neches Link LLC to its joint venture partner, Motiva Enterprises, for gross proceeds of $33 million (US$25 million). As part of the Spinoff Transaction on October 1, 2024, our remaining interest in Port Neches Link LLC was transferred to South Bow.

Acquisitions
In 2023, we acquired 100 per cent of the Class B Membership Interests in the Fluvanna Wind Farm located in Scurry County, Texas for US$99 million, before post-closing adjustments. We also acquired 100 per cent of the Class B Membership Interests in the Blue Cloud Wind Farm located in Bailey County, Texas for US$125 million, before post-closing adjustments.

Loans to affiliate
In 2023, loans to affiliate (issued) repaid, net, represent issuances and repayments on the subordinated demand revolving credit facility and the subordinated loan agreement that we entered with Coastal GasLink LP to provide additional liquidity and funding to the Coastal GasLink project.

Cash (used in) provided by financing activities[1]

year ended December 31 (millions of $)	2025	2024	2023
Notes payable issued (repaid), net	**876**	341	(6,299)
Long-term debt issued, net of issue costs	**5,413**	8,089	15,884
Long-term debt repaid	**(6,116)**	(9,273)	(3,772)
Junior subordinated notes issued, net of issue costs	**2,545**	1,465	—
Dividends and distributions paid	**(4,550)**	(4,807)	(3,052)
Common shares issued, net of issue costs	**104**	88	4
Preferred shares redeemed	**(250)**	—	—
Contributions from non-controlling interests	**—**	21	—
Cash received from factoring arrangement	**351**	—	—
Loan from affiliate	**111**	—	—
Disposition of equity interest, net of transaction costs	**—**	419	5,328
Cash transferred to South Bow, net of debt settlements	**—**	(244)	—
Gains (losses) on settlement of financial instruments	**—**	27	—
Net cash (used in) provided by financing activities	**(1,516)**	(3,874)	8,093

1 Includes continuing and discontinued operations.

Net cash used in financing activities decreased by $2.4 billion in 2025 compared to 2024 primarily due to lower repayments of long-term debt and higher issuances of junior subordinated notes and notes payable, as well as lower dividends and distributions paid in 2025, partially offset by lower issuances of long-term debt.

Net cash provided by financing activities decreased by $12.0 billion in 2024 compared to 2023 primarily due to lower issuances and higher repayments of long-term debt, the receipt of the $5.3 billion (US$3.9 billion) proceeds in 2023 upon sale of a 40 per cent non-controlling equity interest in Columbia Gas and Columbia Gulf, as well as higher dividends and distributions paid in 2024, partially offset by net issuances of notes payable in 2024 compared to net repayments in 2023 and junior subordinated notes issued in 2024.

The principal transactions reflected in our financing activities are discussed in further detail below.

Long-term debt issued

The following table outlines significant long-term debt issuances in 2025.

(millions of Canadian $, unless otherwise noted) Company	Issue date	Type	Maturity date	Amount	Interest rate
TRANSCANADA PIPELINES LIMITED					
	November 2025	Medium Term Notes	November 2055	850	5.13%
	February 2025	Medium Term Notes	February 2035	1,000	4.58%
COLUMBIA PIPELINES HOLDING COMPANY LLC					
	November 2025	Senior Unsecured Notes	November 2032	US 750	5.00%
GREAT LAKES GAS TRANSMISSION LIMITED PARTNERSHIP					
	October 2025	Unsecured Term Loan	October 2028	US 205	Floating
ANR PIPELINE COMPANY					
	September 2025	Senior Unsecured Notes	September 2031	US 250	5.23%
	September 2025	Senior Unsecured Notes	September 2035	US 350	5.69%
COLUMBIA PIPELINES OPERATING COMPANY LLC					
	March 2025	Senior Unsecured Notes	February 2035	US 550	5.44%
	March 2025	Senior Unsecured Notes	February 2055	US 450	5.96%

Long-term debt retired/repaid

The following table outlines significant long-term debt retired/repaid in 2025.

(millions of Canadian $, unless otherwise noted) Company	Retirement/ repayment date	Type	Amount	Interest rate
TRANSCANADA PIPELINES LIMITED				
	November 2025	Senior Unsecured Notes	US 850	4.88%
	October 2025	Senior Unsecured Notes	US 92	7.06%
	July 2025	Medium Term Notes	750	3.30%
NOVA GAS TRANSMISSION LTD.				
	May 2025	Medium Term Notes	87	8.90%
COLUMBIA PIPELINES OPERATING COMPANY LLC				
	March 2025	Senior Unsecured Notes	US 1,000	4.50%
TC PIPELINES, LP				
	March 2025	Senior Unsecured Notes	US 350	4.38%
TC ENERGÍA MEXICANA, S. DE R.L. DE C.V.				
	Various	Senior Unsecured Term Loan	US 677	Floating

On February 5, 2026, TCPL retired $241 million of medium term notes bearing interest at a fixed rate of 8.29 per cent.

Junior subordinated notes issued

The following table outlines significant junior subordinated notes issued in 2025:

(millions of Canadian $, unless otherwise noted) Company	Issue date	Type	Maturity date	Amount	Interest rate
TRANSCANADA PIPELINES LIMITED					
	October 2025	Junior Subordinated Notes	November 2085	US 370	6.25%
	August 2025	Junior Subordinated Notes	February 2056	1,000	5.20% [1]
	February 2025	Junior Subordinated Notes	June 2065	US 750	7.00% [2]

1 Fixed rate of interest per year until February 15, 2031, and resetting every five years thereafter, subject to a rate-reset minimum.

2 Fixed rate of interest per year until June 1, 2030, and resetting every five years thereafter.

Junior subordinated notes repaid/retired

In May 2025, TCPL exercised its option to fully repay and retire the US$750 million junior subordinated notes that had a maturity date of 2075, bearing interest at 5.88 per cent to TransCanada Trust (the Trust). All of the proceeds from the repayment were used by the Trust to fund the redemption price of the US$750 million in aggregate principal amount of outstanding Trust Notes - Series 2015-A, in May 2025 pursuant to their terms. Refer to Note 20, Junior subordinated notes, of our 2025 Consolidated financial statements for additional information.

For more information about long-term debt and junior subordinated notes issued and long-term debt repaid in 2025, 2024 and 2023, refer to Note 19, Long-term debt and Note 20, Junior subordinated notes, of our 2025 Consolidated financial statements.

Dividend reinvestment plan

Under the DRP, eligible holders of common and preferred shares of TC Energy can reinvest their dividends and make optional cash payments to obtain additional TC Energy common shares. From August 31, 2022 to July 31, 2023, common shares were issued from treasury at a discount of two per cent to market prices over a specified period.

Commencing with the dividends declared on July 27, 2023, common shares purchased under TC Energy's DRP are acquired on the open market at 100 per cent of the weighted average purchase price.

Share information

at February 6, 2026		
Common Shares	**issued and outstanding**	
	1.0 billion	
Preferred Shares	**issued and outstanding**	**convertible to**
Series 1	18.4 million	Series 2 preferred shares
Series 2	3.6 million	Series 1 preferred shares
Series 3	11.7 million	Series 4 preferred shares
Series 4	2.3 million	Series 3 preferred shares
Series 5	14.0 million	Series 6 preferred shares
Series 7	24 million	Series 8 preferred shares
Series 9	16.7 million	Series 10 preferred shares
Series 10	1.3 million	Series 9 preferred shares
Options to buy common shares	**outstanding**	**exercisable**
	1.9 million	1.4 million

On January 16, 2026, 109,800 Series 5 preferred shares were elected for conversion, on a one-for-one basis, into Series 6 preferred shares and 1,089,726 Series 6 preferred shares were elected for conversion, on a one-for-one basis, into Series 5 preferred shares. As the total number of Series 6 preferred shares tendered for conversion would have resulted in less than one million Series 6 preferred shares outstanding on the conversion date, all remaining outstanding Series 6 preferred shares were automatically converted into Series 5 preferred shares and no Series 5 preferred shares were converted into Series 6 preferred shares. As a result, on January 30, 2026, 1,929,407 Series 6 preferred shares were converted, on a one-for-one basis, into 1,929,407 Series 5 preferred shares and Series 6 preferred shares were delisted from the TSX at the close of markets on January 30, 2026.

On November 28, 2025, we redeemed all 10 million issued and outstanding Series 11 preferred shares at a redemption price of $25.00 per share and paid the final quarterly dividend of $0.2094375 per Series 11 preferred share for the period up to but excluding November 28, 2025, as previously declared on November 4, 2025.

On June 30, 2025, 104,778 Series 3 preferred shares were converted, on a one-for-one basis, into Series 4 preferred shares and 1,822,829 Series 4 preferred shares were converted, on a one-for-one basis, into Series 3 preferred shares.

For more information on preferred shares, refer to Note 24, Preferred shares, of our 2025 Consolidated financial statements.

Dividends

year ended December 31	2025	2024	2023
Dividends declared			
per common share[1]	**$3.40**	$3.7025	$3.72
per Series 1 preferred share	**$1.23475**	$0.86975	$0.86975
per Series 2 preferred share	**$1.20576**	$1.68134	$1.62659
per Series 3 preferred share	**$0.7245**	$0.4235	$0.4235
per Series 4 preferred share	**$1.04576**	$1.52046	$1.46703
per Series 5 preferred share	**$0.48725**	$0.48725	$0.48725
per Series 6 preferred share	**$1.06655**	$1.55132	$1.55993
per Series 7 preferred share	**$1.49625**	$1.36613	$0.97575
per Series 9 preferred share	**$1.27**	$1.02288	$0.9405
per Series 10 preferred share	**$1.26905**	$0.39807	—
per Series 11 preferred share	**$0.62831**	$0.83775	$0.83775

1 Dividends declared in fourth quarter 2024 and thereafter reflect TC Energy's proportionate allocation following the Spinoff Transaction.

Commencing with the dividends payable on January 31, 2025 to shareholders of record at the close of business on December 31, 2024, the amounts reflect TC Energy's proportionate allocation following the Spinoff Transaction. Refer to our 2024 Annual Report for additional information.

Our Board of Directors have declared a quarterly dividend on our outstanding common shares of $0.8775 per common share for the quarter ending March 31, 2026, which equates to an annual dividend of $3.51 per common share.

Credit facilities

We have several committed credit facilities that support our commercial paper programs and provide short-term liquidity for general corporate purposes. In addition, we have demand credit facilities that are also used for general corporate purposes, including issuing letters of credit and providing additional liquidity.

At February 6, 2026, total committed revolving and demand credit facilities were $11.8 billion. These unsecured credit facilities included the following:

(billions of Canadian $, unless otherwise noted) Borrower	Description	Matures	Total facilities	Unused capacity [1]
Committed, syndicated, revolving, extendible, senior unsecured credit facilities:				
TCPL	Supports commercial paper program and for general corporate purposes	December 2030	3.0	2.3
TCPL / TCPL USA	Supports commercial paper programs and for general corporate purposes of the borrowers, guaranteed by TCPL	December 2026	US 1.0	US 0.7
TCPL / TCPL USA	Supports commercial paper programs and for general corporate purposes of the borrowers, guaranteed by TCPL	December 2028	US 2.5	US 2.2
Columbia Pipelines Holding Company LLC[2]	Supports commercial paper program and general corporate purposes of the borrower	December 2028	US 1.5	US 1.1
Demand senior unsecured revolving credit facilities:				
TCPL / TCPL USA	Supports the issuance of letters of credit and provides additional liquidity; TCPL USA facility guaranteed by TCPL	Demand	2.0 [3]	1.2 [3]

1 Unused capacity is net of commercial paper outstanding and facility draws.
2 Columbia Pipelines Holding Company LLC is a partially owned subsidiary of TC Energy with 40 per cent non-controlling interest.
3 Or the U.S. dollar equivalent.

Contractual obligations

Our contractual obligations include our notes payable, long-term debt and junior subordinated notes, operating leases, purchase obligations and other liabilities incurred in our business such as cash contributions to the employee pension and post-retirement benefit plans.

Payments due (by period)

at December 31, 2025 (millions of $)	Total	< 1 year	1 - 3 years	4 - 5 years	> 5 years
Notes payable	1,200	1,200	—	—	—
Long-term debt and junior subordinated notes[1]	59,145	1,545	8,318	5,882	43,400
Operating leases[2]	509	73	129	122	185
Purchase obligations and other[3]	4,650	1,091	976	564	2,019
	65,504	3,909	9,423	6,568	45,604

1 Excludes issuance costs and fair value adjustments.

2 Includes future payments for corporate offices, various premises, services, equipment, land and lease commitments from corporate restructuring. Some of our operating leases include the option to renew the agreement for one to 25 years.

3 Includes $17 million related to the transfer of pension assets to South Bow. Refer to the Obligations - pension and other post-retirement benefit plans section for additional information.

Notes payable

Total notes payable outstanding at December 31, 2025 was $1.2 billion (2024 – $387 million).

Long-term debt and junior subordinated notes

At December 31, 2025, we had $46.8 billion (2024 – $47.9 billion) of long-term debt and $12.1 billion (2024 – $11.0 billion) of junior subordinated notes.

We attempt to ladder the maturity profile of our debt. The weighted-average maturity of our long-term debt and junior subordinated notes, excluding call features is approximately 19 years.

At December 31, 2025, scheduled interest payments related to our long-term debt and junior subordinated notes were as follows:

at December 31, 2025 (millions of $)	Total	< 1 year	1 - 3 years	4 - 5 years	> 5 years
Long-term debt	29,434	2,387	4,496	3,875	18,676
Junior subordinated notes	44,193	742	1,618	1,677	40,156
	73,627	3,129	6,114	5,552	58,832

Purchase obligations

We have purchase obligations that are transacted at market prices and in the normal course of business, including long-term natural gas transportation and purchase arrangements.

Capital expenditure commitments include obligations related to the construction of growth projects and are based on the projects proceeding as planned. Changes to these projects, including cancellation, would reduce or possibly eliminate these commitments as a result of cost mitigation efforts.

We have entered into PPAs with solar and wind-power generating facilities ranging from 2026 to 2038, that require the purchase of generated energy and associated environmental attributes. At December 31, 2025, the total planned capacity secured under the PPAs is approximately 750 MW with the generation subject to operating availability and capacity factors. These PPAs do not meet the definition of a lease or derivative. Future payments and their timing cannot be reasonably estimated as they are dependent on when certain underlying facilities are placed in service and the amount of energy generated. Certain of these purchase commitments have offsetting sale PPAs for all or a portion of the related output from the facility.

At December 31, 2025, payments for purchase obligations and other were as follows:

at December 31, 2025 (millions of $)	Total	< 1 year	1 - 3 years	4 - 5 years	> 5 years
Canadian Natural Gas Pipelines					
Transportation by others[1]	181	41	77	45	18
Transportation by others - TQM[1,2]	2,574	152	317	316	1,789
Capital spending[3]	115	115	—	—	—
U.S. Natural Gas Pipelines					
Transportation by others[1]	598	144	249	91	114
Capital spending[3]	569	311	180	78	—
Mexico Natural Gas Pipelines					
Capital spending[3]	36	36	—	—	—
Power and Energy Solutions					
Capital spending[3]	114	78	28	6	2
Other	190	26	40	28	96
Corporate					
Capital spending[3]	3	3	—	—	—
South Bow pension plan assets held in trust[4]	17	17	—	—	—
Other	253	168	85	—	—
	4,650	1,091	976	564	2,019

1 Demand rates are subject to change. The contractual obligations in the table are based on demand volumes only and exclude variable charges incurred when volumes flow.

2 Includes 100 per cent of the contracted obligation for the Canadian Mainline to transport volumes for its shippers utilizing the TQM pipeline to 2042, which we have a 50 per cent ownership interest in. The cost of the contracts flow through to the Canadian Mainline shippers and is determined based on the revenue requirement outlined in the TQM settlement agreement.

3 Amounts are primarily for expenditures for capital projects. Amounts are estimates and are subject to variability based on timing of construction and project requirements.

4 Related to the transfer of pension assets to South Bow. Refer to the Obligations - pension and other post-retirement benefit plans section for additional information.

GUARANTEES

Sur de Texas

We and our partner on the Sur de Texas pipeline, IEnova Infraestructura Marina Holding B.V. (IEnova), have jointly guaranteed the financial performance of the entity which owns the pipeline. Such agreements include a guarantee and a letter of credit which are primarily related to the delivery of natural gas. The guarantee has terms that can be renewed in June 2026, with the annual option to extend for one year periods ending in 2053.

At December 31, 2025, our share of potential exposure under the Sur de Texas pipeline guarantees was estimated to be $78 million with a carrying amount of less than $1 million.

Bruce Power

We and our joint venture partner on Bruce Power, BPC Generation Infrastructure Trust, have each severally guaranteed certain contingent financial obligations of Bruce Power related to a lease agreement. The Bruce Power guarantee has a term that can be renewed in December 2027 and is extendable for any number of successive two-year periods, with a final renewal period of three years ending in 2065.

At December 31, 2025, our share of the potential exposure under the Bruce Power guarantee was estimated to be $88 million with no carrying amount.

Other jointly-owned entities

We and our partners in certain other jointly-owned entities have also guaranteed (jointly, severally, jointly and severally, or exclusively) the financial performance of these entities. Such agreements include guarantees and letters of credit which are primarily related to delivery of natural gas. The guarantees have terms ranging to 2032.

Our share of the potential exposure under these assurances was estimated at December 31, 2025 to be approximately $54 million with a carrying amount of $1 million. In certain cases, if we make a payment that exceeds our ownership interest, the additional amount must be reimbursed by our partners.

OBLIGATIONS – PENSION AND OTHER POST-RETIREMENT BENEFIT PLANS

In 2025, we made no funding contributions to our defined benefit pension plans (DB Plans), $8 million for other post-retirement benefit plans and $72 million for the savings plan and defined contribution plans. Total letters of credit provided for the funding of solvency requirements to the Canadian DB plan at December 31, 2025 was nil (2024 – $111 million; 2023 – $244 million).

In 2026, we do not expect to make any contributions to the DB Plans, $8 million of funding contributions for other post-retirement benefit plans and $76 million for the savings plans and defined contribution pension plans. We do not expect to issue additional letters of credit to the Canadian DB Plan for the funding of solvency requirements.

The net benefit cost for our DB Plans and other post-retirement plans decreased to $11 million in 2025 from $19 million in 2024 primarily due to decrease service costs in the Canadian retirement plan.

South Bow - transition of pension assets

As part of the Spinoff Transaction, certain TC Energy employees became employees of South Bow. Prior to the Spinoff Transaction, these employees in Canada and the U.S. participated in DB Plans, DC Plans and savings plans, as applicable. Effective October 1, 2024, the benefit obligations under the DB Plans in respect of the employees moving from TC Energy to South Bow were transferred to South Bow. An asset transfer application related to the Canadian DB Plan outlining the proposed transfer of assets from TC Energy to South Bow has received regulatory approval. During the year ended December 31, 2025, $105 million was transferred to South Bow. As at December 31, 2025, $17 million of assets in the Canadian DB Plan remain in the TC Energy DB Plan trust and are reflected as Current assets of discontinued operations with a corresponding obligation to South Bow reflected as Current liabilities of discontinued operations on our Consolidated balance sheet. The remaining South Bow pension assets will be adjusted to fair value on the date of transfer, which is expected mid-2026. As at December 31, 2024, the assets related to the U.S. DB Plan were fully transferred to South Bow.

Future net benefit costs and the amount we will need to contribute to fund our plans will depend on a range of factors including:

- interest rates
- actual returns on plan assets
- changes to actuarial assumptions and plan design
- actual plan experience versus projections
- amendments to pension plan regulations and legislation.

We do not expect future increases in the level of funding needed to maintain our plans to have a material impact on our liquidity or financial condition.

Discontinued operations

On October 1, 2024, TC Energy completed the spinoff of its Liquids Pipelines business into the new public company, South Bow. Upon completion of the Spinoff Transaction, the Liquids Pipelines business was accounted for as a discontinued operation.

Agreements

Pursuant to the Spinoff Transaction, TC Energy and South Bow have executed a series of agreements to outline the parameters and guidelines that govern their ongoing relationship, including a Transition Services Agreement, Tax Matters Agreement and a Separation Agreement.

The Transition Services Agreement was established to specify certain services that TC Energy will provide to South Bow for a period of up to two years.

The Tax Matters Agreement imposes certain restrictions on both TC Energy and South Bow in order to preserve the tax-free status of the spinoff and allocates tax liabilities in the event the Spinoff Transaction is not tax-free.

The Separation Agreement sets forth the terms of the separation of the Liquids Pipelines business from the business of TC Energy, including the transfer of certain assets related to the Liquids Pipelines business from TC Energy to South Bow and the allocation of certain liabilities and obligations related to the Liquids Pipelines business between TC Energy and South Bow.

In September 2025, we reached an agreement with South Bow with respect to liabilities we indemnified South Bow for under the Separation Agreement, releasing us from those liabilities. Inclusive of the recognition of the settlement, a net after-tax loss from discontinued operations of $183 million was recorded for the year ended December 31, 2025 and has been excluded from our calculation of comparable measures from discontinued operations. Payments related to the settlement commenced in fourth quarter 2025 and will be completed in 2026.

In June 2025, we received $24 million related to certain recoveries under the Separation Agreement with South Bow. At this time, we also revised our estimate of our share of future recoveries, resulting in a $29 million impairment charge, which has been included in Net income (loss) from discontinued operations, net of tax in the Consolidated statement of income and excluded from our calculation of comparable measures from discontinued operations.

For additional information regarding the agreement, incidents occurring prior to the Spinoff Transaction and separation costs, refer to Note 4, Discontinued operations, of our 2025 Consolidated financial statements and our 2024 Annual Report.

Presentation of Discontinued Operations

Upon completion of the Spinoff Transaction, the Liquids Pipelines business was accounted for as discontinued operations. Our presentation of discontinued operations includes revenues and expenses directly attributable to the Liquids Pipelines business.

Prior years' amounts present the Liquids Pipelines business as discontinued operations.

RESULTS FROM DISCONTINUED OPERATIONS[1]

year ended December 31 (millions of $, except per share amounts)	2025	2024	2023
Segmented earnings (losses) from discontinued operations	**(245)**	716	1,039
Interest expense	**—**	(218)	(297)
Interest income and other	**28**	21	(30)
Income (loss) from discontinued operations before income taxes	**(217)**	519	712
Income tax (expense) recovery	**5**	(124)	(100)
Net income (loss) from discontinued operations, net of tax	**(212)**	395	612
Net income (loss) per common share from discontinued operations – basic	**($0.20)**	$0.38	$0.60

1 Represents nine months of Liquids Pipelines earnings in 2024 and a full year of earnings in 2023.

Net loss from discontinued operations, net of tax in 2025 was $212 million or $0.20 per common share (2024 – net income of $395 million or $0.38 per common share; 2023 – net income of $612 million or $0.60 per common share), a decrease of $607 million or $0.58 per common share compared to 2024 and a decrease of $217 million or $0.22 per common share in 2024 compared to 2023.

NON-GAAP MEASURES

This MD&A references non-GAAP measures, which are described on page 22. These measures do not have any standardized meaning as prescribed by GAAP and therefore may not be comparable to similar measures presented by other entities.

The following specific items were recognized in Net income (loss) from discontinued operations, net of tax and were excluded from comparable earnings from discontinued operations:

2025

- a pre-tax charge of $188 million primarily related to the liabilities we indemnified South Bow for under the Separation Agreement
- a pre-tax impairment charge of $29 million related to our estimate of Keystone XL contractual recoveries.

2024

- a pre-tax charge of $197 million from Liquids Pipelines business separation costs related to the Spinoff Transaction, of which $173 million was recognized in segmented earnings (losses) from discontinued operations, $42 million was recorded in interest expense and $18 million was recorded in interest income
- a pre-tax expense of $37 million related to our estimate of potential incremental costs resulting from the Milepost 14 incident. This amount represents our 86 per cent share pursuant to the indemnity provisions in the Separation Agreement
- a pre-tax expense of $21 million related to Keystone XL asset disposition and termination activities
- a pre-tax charge of $12 million as a result of the FERC Administrative Law Judge decision on Keystone in respect of a tolling-related complaint pertaining to amounts recognized in prior periods.

2023

- a pre-tax charge of $67 million as a result of the FERC Administrative Law Judge decision on Keystone in respect of a tolling-related complaint pertaining to amounts recognized in prior periods, which consists of a one-time pre-tax charge of $57 million and included accrued pre-tax carrying charges of $10 million
- a pre-tax charge of $40 million from Liquids Pipelines business separation costs related to the Spinoff Transaction
- a pre-tax accrued insurance expense of $36 million related to the Milepost 14 incident
- pre-tax preservation and other costs of $18 million related to the preservation and storage of the Keystone XL pipeline project assets
- a pre-tax recovery of $4 million related to the net impact of a U.S. minimum tax recovery on the 2021 Keystone XL asset impairment charge and other and a gain on the sale of Keystone XL project assets, offset partially by adjustments to the estimate for contractual and legal obligations related to termination activities.

Reconciliation of net income (loss) from discontinued operations, net of tax to comparable earnings from discontinued operations[1]

year ended December 31 (millions of $, except per share amounts)	2025	2024	2023
Net income (loss) from discontinued operations, net of tax	**(212)**	395	612
Specific items (pre tax):			
South Bow settlement[2]	**188**	—	—
Keystone XL asset impairment charge and other	**29**	21	(4)
Liquids Pipelines business separation costs	**—**	197	40
Milepost 14 incremental costs	**—**	37	—
Keystone regulatory decisions	**—**	12	67
Milepost 14 insurance expense	**—**	—	36
Keystone XL preservation and other	**—**	—	18
Risk management activities	**—**	(67)	34
Taxes on specific items	**(5)**	(30)	(47)
Comparable earnings from discontinued operations	**—**	565	756
Net income (loss) per common share from discontinued operations	**($0.20)**	$0.38	$0.60
Specific items (net of tax)	**0.20**	0.16	0.14
Comparable earnings per common share from discontinued operations	**—**	$0.54	$0.74

1 Represents nine months of Liquids Pipelines earnings in 2024 and a full year of earnings in 2023.

2 A pre-tax charge of $188 million for the year ended December 31, 2025 primarily resulting from the resolution reached in September 2025 under the Separation Agreement with South Bow.

Comparable EBITDA to comparable earnings - from discontinued operations[1]

Comparable EBITDA from discontinued operations represents segmented earnings (losses) from discontinued operations adjusted for the specific items described above and excludes charges for depreciation and amortization.

year ended December 31 (millions of $, except per share amounts)	2024	2023
Comparable EBITDA from discontinued operations	1,145	1,516
Depreciation and amortization	(253)	(332)
Interest expense included in comparable earnings[2]	(176)	(287)
Interest income and other included in comparable earnings[3]	3	6
Income tax (expense) recovery included in comparable earnings[4]	(154)	(147)
Comparable earnings from discontinued operations	565	756
Comparable earnings per common share from discontinued operations	$0.54	$0.74

1 Represents nine months of Liquids Pipelines earnings in 2024 and a full year of earnings in 2023.
2 Excludes pre-tax Liquids Pipelines business separation costs of $42 million related to interest expense on the South Bow debt issuance in third quarter 2024 and carrying charges of $10 million for the year ended December 31, 2023 as a result of a pre-tax charge related to the FERC Administrative Law Judge decision on Keystone in respect of a tolling-related complaint pertaining to amounts recognized in prior periods.
3 Excludes pre-tax income of $18 million for the year ended December 31, 2024 related to the net impact of interest income on proceeds from the South Bow debt issuance on August 28, 2024, which were held in escrow and insurance provisions as well as a $36 million pre-tax insurance expense recorded in 2023 related to the Milepost 14 incident.
4 Excludes the impact of income taxes related to the specific items mentioned above as well as a $14 million U.S. minimum tax recovery in 2023 on the Keystone XL asset impairment charge and other related to the termination of the Keystone XL pipeline project.

Comparable EBITDA from discontinued operations

Comparable EBITDA from discontinued operations was $371 million lower in 2024 compared to 2023 primarily due to the net effect of:

- nine months of Liquids Pipelines earnings included in 2024 compared to a full year of Liquids Pipelines earnings in 2023
- higher contracted and uncontracted volumes across the Keystone Pipeline System in 2024
- lower contributions from the liquids marketing business due to lower realized margins.

Comparable earnings from discontinued operations

Comparable earnings from discontinued operations in 2024 were $191 million or $0.20 per common share lower than in 2023, and were primarily due to the impact of nine months of Liquids Pipelines business earnings in 2024 compared to a full year in 2023.

FINANCIAL RESULTS - 2024 and 2023[1]

The following is a reconciliation of comparable EBITDA from discontinued operations and comparable EBIT from discontinued operations (our non-GAAP measures) to segmented earnings (losses) from discontinued operations (the most directly comparable GAAP measure). Refer to page 22 for more information on non-GAAP measures we use.

For information on 2025 comparable measures from discontinued operations refer to page 89.

year ended December 31 (millions of $)	2024	2023
Keystone Pipeline System	1,098	1,453
Intra-Alberta pipelines[2]	52	70
Other	(5)	(7)
Comparable EBITDA from discontinued operations	1,145	1,516
Depreciation and amortization	(253)	(332)
Comparable EBIT from discontinued operations	892	1,184
Specific items (pre tax):		
Liquids Pipelines business separation costs	(173)	(40)
Milepost 14 incremental costs	(37)	—
Keystone XL asset impairment charge and other	(21)	4
Keystone regulatory decisions	(12)	(57)
Keystone XL preservation and other	—	(18)
Risk management activities	67	(34)
Segmented earnings (losses) from discontinued operations	716	1,039

1 Represents nine months of Liquids Pipelines earnings in 2024 and a full year of earnings in 2023.
2 Intra-Alberta pipelines includes Grand Rapids and White Spruce.

Segmented earnings from discontinued operations decreased by $323 million in 2024 compared to 2023 and included the specific items mentioned in the table above, which have been excluded from our calculation of comparable EBITDA from discontinued operations and comparable EBIT from discontinued operation. Refer to page 89 for additional information.

A stronger U.S. dollar in 2024 and 2023 had a positive impact on the Canadian dollar equivalent segmented earnings from our U.S. operations.

Depreciation and amortization

Depreciation and amortization was $79 million lower in 2024 compared to 2023 due to nine months of Liquids Pipelines operations in 2024 compared to a full year of Liquids Pipelines operations in 2023.

Interest expense[1]

year ended December 31 (millions of $)	2024	2023
Interest expense included in comparable earnings from discontinued operations	(176)	(287)
Specific items:		
Liquids Pipelines business separation costs	(42)	—
Keystone regulatory decisions	—	(10)
Interest expense from discontinued operations[2]	(218)	(297)

1 Represents nine months of Liquids Pipelines allocated interest expense in 2024 and a full year of allocated interest expense in 2023.
2 We have elected to allocate a portion of the interest expense incurred at the corporate level to discontinued operations. Refer to our 2024 Annual Report for additional information.

Interest expense included in comparable earnings from discontinued operations decreased by $111 million in 2024 compared to 2023 due to nine months of interest expense included in 2024 compared to a full year in 2023.

Interest income and other[1]

year ended December 31 (millions of $)	2024	2023
Interest income and other included in comparable earnings from discontinued operations	3	6
Specific items:		
Liquids Pipelines business separation costs	18	—
Milepost 14 insurance expense	—	(36)
Interest income and other from discontinued operations	21	(30)

1 Represents nine months of Liquids Pipelines earnings in 2024 and a full year of earnings in 2023.

Interest income and other included in comparable earnings from discontinued operations was generally consistent 2024 compared to 2023.

Income tax (expense) recovery[1]

year ended December 31 (millions of $)	2024	2023
Income tax (expense) recovery included in comparable earnings from discontinued operations	(154)	(147)
Specific items:		
Liquids Pipelines business separation costs	30	6
Milepost 14 incremental costs	9	—
Keystone XL asset impairment charge and other	5	14
Keystone regulatory decisions	2	15
Keystone XL preservation and other	—	4
Risk management activities	(16)	8
Income tax (expense) recovery from discontinued operations	(124)	(100)

1 Represents nine months of Liquids Pipelines earnings in 2024 and a full year of earnings in 2023.

Income tax expense included in comparable earnings from discontinued operations increased by $7 million in 2024 compared to 2023 primarily due to lower foreign income tax rate differentials largely offset by lower earnings.

Other information

RISK OVERSIGHT AND ENTERPRISE RISK MANAGEMENT

Risk management is embedded in all activities at TC Energy and is integral to the successful operation of our business. Our strategy ensures that risks and related exposures are aligned with our business objectives and risk tolerances. We achieve this through a centralized Enterprise Risk Management (ERM) program, which systematically identifies and assesses risks that could materially impact our strategic objectives.

The ERM program addresses risks related to executing our business strategies and supports practices for identifying and monitoring emerging risks. Specifically, the ERM framework offers a comprehensive process for risk identification, analysis, evaluation and mitigation. It also ensures ongoing monitoring and reporting to the Board of Directors, CEO, Executive Vice-Presidents and the Chief Risk Officer.

Board and Committee Oversight

Our Board of Directors retains general oversight over all enterprise risks. Annually, the Board reviews the enterprise risk register and receives quarterly updates on emerging risks and their management and mitigation in accordance with TC Energy's risk appetite and tolerances. Additionally, the Board receives detailed presentations on enterprise risks quarterly, with specific themes addressed during regular financial updates and strategic meetings. Special presentations are also delivered as needed or upon request.

The Governance Committee of our Board oversees the ERM program, ensuring comprehensive oversight of our risk management activities. In addition, other Board committees oversee specific risk types within their mandates:

- the Human Resources Committee oversees executive resourcing, organizational capabilities and compensation risk to ensure human and labour policies and remuneration practices align with our overall business strategy
- the HSSE Committee oversees operational, major project execution, health, safety, sustainability and environmental risks, including climate-related risks
- the Audit Committee oversees management's role in mitigating financial risk, including market risk, insurance risk, counterparty credit risk and cybersecurity risk.

Executive Leadership and Risk Management

Our Executive Leadership team is responsible for developing and implementing risk management plans and actions, with effective risk management reflected in their compensation. Each identified enterprise risk has a governance owner from the executive leadership team. Risk execution is overseen by an accountable business unit President or Senior Vice-President. These risk owners provide in-depth risk reviews to the Board annually.

Segment-Specific Risks

Key segment-specific financial, health, safety and environment-related risks are covered in their respective sections of this MD&A. Further, our Report on Sustainability provides information on our approach to sustainability, including the oversight of sustainability-related risks and opportunities.

Enterprise Risk Monitoring and Key Risk Indicators

Risks related to our key enterprise risk themes are continuously monitored through our ERM program. The program includes a network of emerging risk liaisons strategically positioned across the organization, responsible for identifying potential enterprise-level risks and reporting them quarterly to the Board of Directors.

Additionally, as part of our ongoing commitment to enhancing the ERM program, we employ Key Risk and Performance Indicators (KRIs) to monitor risk events that could impact our strategic objectives. These KRIs provide quantifiable metrics, objective rationale and meaningful trends for each enterprise risk, helping to inform the annual in-depth review of enterprise risks conducted by the Board.

Operational risk

Across North America, TC Energy manages a vast natural gas transmission network that includes numerous facilities, gas storage reservoirs and power-generation plants. Operational risks include the potential for significant ruptures or failures, especially in regions where pipelines traverse populated areas. Key factors contributing to these risks include integrity threats such as corrosion, cracking and manufacturing defects and third-party damage. Additionally, aging infrastructure and the potential for extreme weather conditions and other external forces further increase the likelihood of significant ruptures or operational failures.

The consequences of a significant rupture or operational failure can be severe and multifaceted. Potential impacts include loss of human life or severe injuries, environmental damage and extensive operational disruptions. Financial repercussions are also considerable, encompassing costs related to incident response, repairs, fines and penalties. Furthermore, such incidents can lead to incremental regulatory enforcement and reputational harm, which may strain customer relationships and jeopardize future projects.

To ensure the safe and reliable operation of its assets, TC Energy employs a robust Operational Management System, TOMS, that integrates comprehensive risk management and asset integrity practices. Current measures include a quantitative operational risk assessment process, integrity management programs and advanced inline inspection technologies. We also conduct failure investigations and root cause analyses to drive continuous improvement. Governance and oversight by senior management, along with an Emergency Management Program, ensure preparedness and effective response to potential incidents. TOMS standards, processes and procedures are continually improved based on lessons learned from internal and external incidents, as well as collaborative work with industry peers and regulators.

Regulatory risk

TC Energy operates in a highly regulated industry across North America, requiring various permits and approvals from federal, state, provincial and local government agencies. The regulatory landscape is highly complex, with overlapping and sometimes conflicting requirements from various levels of government. Changes in government can further introduce uncertainty and delays in obtaining necessary permits. Additionally, opposition groups can influence regulatory decisions through organized protests, legal challenges and negative media campaigns.

Failure to obtain or maintain regulatory approvals for energy infrastructure projects can lead to substantial financial and operational consequences. These include delays or cancellations of critical projects, increased operating costs due to additional compliance requirements and disruptions to existing infrastructure. Financial impacts also encompass lost development costs, reduced investor confidence and higher capital costs. Moreover, negative publicity and public opposition can damage our reputation, erode public trust and hinder our ability to operate effectively. These challenges can ultimately affect our competitive position and ability to meet growth objectives.

To address this risk, we have implemented several monitoring and mitigation strategies. These include proactive efforts to monitor the evolving regulatory environment, engage in strategic advocacy across all levels of government, cultivate enduring trust and alignment with stakeholders and respond promptly to emerging issues and concerns. These activities are designed to secure necessary approvals to support our growth objectives and mitigate potential delays and disruptions.

Access to capital at a competitive cost

We require significant capital in the form of debt and equity to finance our growth projects and manage maturing debt obligations. It is essential that we secure this capital at costs lower than the returns on our investments. Deterioration in market conditions, changes in investor and lender sentiment, geopolitical instability, higher interest rates and persistent inflation could adversely affect our access to and cost of capital. Additionally, factors such as investor ESG exclusionary screening, capacity limitations in capital markets and economic uncertainties can further compound these risks, potentially leading to higher borrowing costs and constrained growth.

A higher cost of capital can negatively impact our ability to deliver attractive returns on investments and inhibit both short- and long-term growth. This could adversely affect our earnings and undermine the viability of capital projects. Additionally, higher costs can negatively impact investor confidence, the reported value of assets and liabilities and our overall financial performance.

TC Energy employs a comprehensive strategy to monitor and mitigate these risks. Current mitigations include maintaining a high-quality and diversified banking syndicate, proactive engagement with lenders and credit rating agencies and balancing issuance strategies across multiple capital markets. We also actively manage our foreign exchange risk through hedging strategies and maintain a balanced debt portfolio to manage interest rate exposure. Ongoing mitigations involve developing new lending relationships and enhancing engagement with ESG-focused investors. Additionally, TC Energy continuously monitors government policies and industry developments to proactively address potential influences on capital flows.

Capital allocation

To remain competitive, TC Energy must provide essential energy infrastructure services in both supply and demand areas, offering solutions that appeal to our customers, while maintaining alignment with our strategic objectives. Capital allocation challenges include balancing investments to defend our existing footprint and service our customer base, investing in the highest-return, lowest-risk opportunities within our discretionary annual net capital limit and shaping the capital program to optimally utilize available capital.

Inefficient capital allocation can lead to the misallocation of financial resources to projects that do not align with our strategic objectives, increase exposure to high-risk projects and reduce financial performance. Additionally, failure to adapt to changing energy supply and demand fundamentals, including those related to lower-carbon forms of energy, may result in reputational damage, regulatory risks and the potential for stranded assets. Diversifying capital into emerging or alternative energy businesses before technologies, commercial models, and regulatory frameworks have matured also poses risk. Overall, these risks can cause strategic misalignment and diminish shareholder value.

We have a rigorous governance process to maintain capital allocation discipline. We limit annual net capital expenditures and high-grade our project development pipeline for purposes of pursuing lower risk and higher value opportunities. We also conduct analyses to confirm the resilience of the supply and demand markets we serve as part of our strategic reviews and regularly monitor industry trends and regulatory developments. Continuous improvements to the capital allocation process include enhanced investment review and due diligence, as well as conducting long-term scenario analyses to understand the portfolio effects of capital allocation choices.

Capital recovery risk

Capital recovery risk pertains to the challenge of both earning an acceptable return on invested capital and recovering the initial investment. This risk arises from potential misalignment between deal structures and our risk preferences, leading to capital exposure. Key contributors include inadequate risk assessments, difficulties in stakeholder collaboration, unforeseen changes in project scope or environment, financial constraints, macroeconomic volatility, counterparty risk, regulatory risk and evolving public policy. Collectively, these factors threaten our financial stability and strategic objectives.

The inability to recover a return on capital can lead to unexpected capital expenditures, significant financial losses and reduced returns. It can erode trust and credibility with partners, investors, regulators and other key stakeholders. Additionally, poorly structured deals may divert management's focus from core business activities to address arising issues, further impacting operational efficiency. The broader consequences include potential damage to our reputation and investor confidence, which are crucial for sustaining long-term growth and stability and preserving shareholder value.

TC Energy employs a robust due diligence process that includes comprehensive risk assessments and detailed contract negotiations. Continuous monitoring of risk exposures and mitigation measures is conducted throughout the lifecycle of each deal, high-grading our project development pipeline to the lowest-risk, highest-value opportunities. Proactive engagement with counterparties and strategic partnerships helps manage and share risks effectively. Depreciation is recovered through regulated pipeline rates, allowing us to accelerate or decelerate the return of capital from our assets. Additionally, we leverage our diversified asset base and long-term contracts to stabilize cash flows and reduce exposure to market volatility.

Project execution

Investing in large infrastructure projects requires significant capital commitments and carries considerable project execution risks. Potential shortages of skilled labour and expertise, supply chain lead times and disruptions and increasing project and regulatory complexity are among these risks. Collectively, these factors can lead to cost overruns, schedule delays, suboptimal project performance and increased safety vulnerabilities, ultimately impacting our financial performance, reputation and strategic growth.

Failure to effectively manage these risks can result in significant financial and operational consequences. Cost overruns and schedule delays can undermine the profitability and feasibility of projects, leading to increased contractual claims and disputes. Additionally, inadequate project execution can damage our reputation, reduce investor confidence and hinder future growth opportunities.

To help mitigate these risks, our Project Delivery System is integrated with our capital allocation process and is aligned with TOMS, optimizing project execution for safe, timely and on-budget performance. We develop projects to a sufficient maturity level to fully understand scope, cost, schedule and execution risk prior to sanctioning. This approach enables us to identify and consult stakeholders and proactively address project-specific constraints and risks. Commercial contracts are structured to recover development costs and minimize the impact of potential cost overruns, explicitly sharing execution risk where warranted. Additionally, we leverage project financing and partner involvement to manage capital at risk.

Talent risk

TC Energy's success hinges on attracting, retaining and developing a talented workforce with a deep understanding of the energy industry, geopolitical environment and various regulatory regimes across North America. Key talent-related risks include the loss of critical personnel, difficulties in securing and retaining talent in a highly competitive market and health and wellness issues that could impact workforce productivity.

Failure to manage talent-related risk can lead to several adverse outcomes, including a decline in employee morale and engagement, resulting in reduced productivity, efficiency and quality of work. High resignation rates, particularly among top talent, can disrupt operations and continuity, leading to increased recruitment and training costs. The organization may also face reputational damage if perceived as failing to address employee concerns, impacting its ability to attract and retain future talent. Furthermore, operational disruptions and a disengaged workforce can pose health and safety risks, ultimately affecting our overall performance and strategic execution.

To mitigate these risks, TC Energy employs a comprehensive talent risk management framework to assess needs and prioritize initiatives. We focus on employee development, engagement and well-being to foster a positive work environment and retain top talent. Our competitive approach to pay for performance promotes fairness and transparency in compensation practices, while our succession planning process ensures a steady pipeline of talented individuals are prepared to assume critical roles. Regular employee engagement surveys help us translate employee input into meaningful action and improvements. Additionally, we have integrated inclusion and equal opportunity initiatives into our talent management strategies and implemented a hybrid work schedule to offer greater flexibility. Collectively, this approach promotes employee retention, minimizes the impact of potential talent losses and guides targeted development actions.

Enterprise security

Ensuring the security of our stakeholders, staff and our assets is paramount to maintaining the safety and reliability of our operations. Security risks encompass potential cyberattacks on industrial control systems and corporate digital assets, unauthorized data disclosures and physical attacks on our infrastructure. These risks are heightened by the increasing sophistication of cyber tactics, rising geopolitical tensions and the critical nature of our business.

A security incident can result in the misuse or disruption of critical information and functions, cause damage to our assets and potentially lead to safety and/or environmental incidents. Resulting service interruptions may have cascading effects on supply chains, customer relationships and strategic goals. Additionally, such incidents can harm our reputation and trigger regulatory enforcement actions or litigation, negatively impacting our operations and/or financial position.

TC Energy maintains an enterprise security program that encompasses both cyber and physical security. Our program is based on standards, assurance and risk management combining prevention and mitigation activities. Our preventative efforts include deploying advanced security technology, defining secure processes, implementing enhanced security measures for high-risk staff or facilities and delivering cyber and physical security awareness programs. Our mitigative activities include proactive monitoring and response to potential security incidents. We also maintain and regularly test incident response plans to manage and mitigate the impact of potential security incidents, including cyberattacks. To further mitigate potential risks, we maintain insurance coverage against cyber and physical security incidents. To mitigate risks associated with third-party vendors and suppliers, we conduct vendor risk assessments, which includes evaluations of security standards, contractual safeguards and ongoing monitoring.

We collaborate with government security agencies, law enforcement and industry to stay informed and be proactive on evolving threats. Our prevention and mitigation strategies for both cyber and physical security are regularly reviewed and updated to align with regulatory and industry standards. The status of our enterprise security program is reported to the Audit Committee quarterly.

TC Energy remains committed to continually improving our security posture and adapting to the ever-evolving threat landscape. By prioritizing security and investing in technologies and practices, we strive to protect our stakeholders, staff, assets, operations and ensure the long-term sustainability of our business.

Climate-related risks

Our business, operations, financial condition and performance may be impacted by both the physical risks associated with climate change and the transition risks arising from the global transition to a lower-carbon economy. Climate-related risks, including changes to climate policy and related developments, may intersect with and influence the enterprise risks outlined above. Therefore, these risks are systematically considered and assessed as part of our risk management framework.

We periodically conduct climate scenario analysis to support our strategic planning and risk management processes. This allows us to assess the resiliency of our business strategy and strengthen our understanding of potential climate-related risks and opportunities across various energy transition pathways. We do not assign probabilities to these scenarios, nor do we consider them to be forecasts or expected outcomes.

Physical Risks

Physical climate hazards caused by climate change can be either event-driven (acute), with immediate, severe impacts, or gradual (chronic), resulting from persistent, long-term shifts in climate patterns. The frequency and severity of climate hazards, particularly acute weather events, are difficult to predict. Climate hazards vary greatly across different geographical regions depending on weather patterns, topography and proximity to bodies of water. Many of our natural gas pipeline assets are underground, inherently reducing the exposure to certain types of climate hazards. Exposure to physical climate hazards could have significant financial implications, such as unexpected costs resulting from direct damage to our assets, additional costs for preventative measures, loss of revenues due to business interruption, or indirect effects such as value chain disruption.

If our exposure to climate hazards intensifies, we can implement preventative measures to enhance the resilience of our assets, tailoring these measures to the nature of the hazard and the characteristics of each asset. Additionally, our emergency response plans focus on quickly and effectively responding to severe weather events to minimize impacts. As a further risk mitigation measure, we maintain insurance coverage to reduce the financial impact associated with damage to our assets due to extreme weather events. However, insurance does not cover all events in all circumstances and we may experience an increase in insurance premiums and deductibles, or a decrease in available coverage for our assets in areas subject to severe weather.

Transition Risks

Transition risks arise from the global shift toward a lower-carbon economy, and include policy, legal, technological, market and reputational risks. These risks may involve changes in energy supply and demand trajectories, the pace and reliability of technological advancements, changes in decarbonization policies and regulations and stakeholder perceptions of our role in the transition to a lower-carbon economy.

Financial implications could include asset impairments due to new or amended climate-related regulations, reduced demand for fossil fuels, challenges in permitting projects and limited access to and/or increased cost of capital. Our financial performance could also be impacted by shifting consumer demands, insolvency of our significant customers and the development and deployment of new technologies.

In the medium term, these risks would be partially mitigated through our low-risk business model, whereby much of our earnings are underpinned by regulated cost-of-service arrangements and/or long-term contracts with credit-worthy counterparties. Regulators also often permit accelerated depreciation of regulated assets, allowing faster recovery of asset value and helping offset potential terminal value risk if climate policies shorten asset life.

A shift to a lower-carbon economy could also present substantial investment opportunities in emerging energy markets and technologies. Our existing capabilities in lower-carbon energy generation, including nuclear power and energy storage technologies, could enable us to capitalize on new lower-carbon energy opportunities. Our pipeline network across North America also provides an extensive footprint of linear infrastructure that could be leveraged to transport emerging clean fuels like hydrogen and renewable natural gas, as well as to facilitate the transportation of captured carbon emissions for sequestration.

Additional information on our climate strategy and climate-related risks and opportunities can be found in the climate-related disclosures section of our annual Report on Sustainability.

Health, safety, sustainability and environmental matters

The Board's HSSE Committee oversees operational risk, major project execution risk, occupational and process safety, sustainability, security of personnel, environmental and climate change-related risks, as well as monitoring development and implementation of systems, programs and policies relating to HSSE matters through regular reporting from management. We use an integrated management system that establishes a framework for managing these risks and is used to capture, organize, document, monitor and improve our related policies, standards and procedures.

TC Energy's Operational Management System, TOMS, leverages industry best practices and standards and incorporates applicable regulatory requirements. TOMS governs health, safety, environment and operational integrity matters at TC Energy. It is applicable across Canada, the U.S. and Mexico throughout the lifecycle of our assets and employs a continuous improvement cycle. The TOMS framework leverages continuous improvement through an annual management review process. This ensures the ongoing effectiveness of our overarching management system and supports a tiered assurance structure across all business units. The TC Energy assurance model is designed to provide effective management of health, safety, environmental and operational integrity risks. Lessons learned are consistently shared and applied across our system where applicable. Additionally, any findings or insights from periodic audits conducted by our external regulators are also shared across the elements of our management system to ensure continuous improvement.

The HSSE Committee reviews performance and operational risk management. It receives updates and reports on:

- overall HSSE corporate governance
- operational performance
- asset integrity
- significant occupational safety and process safety incidents
- occupational and process safety performance metrics
- occupational health, safety and industrial hygiene, which includes physical and mental health, as well as psychological safety
- emergency preparedness, incident response and evaluation
- environment, including biodiversity and land reclamation
- developments in and compliance with, applicable legislation and regulations, including those related to climate and the environment
- prevention, mitigation and management of risks related to HSSE matters, including climate policy or business interruption risks, such as pandemics, which may adversely impact TC Energy
- sustainability matters, including social, environmental and climate-related risks and opportunities, as well as related non-regulatory public disclosures such as our annual Report on Sustainability, our Reconciliation Action Plan and updates on the progression of our commitments.

There are two separate committees that report to the Board HSSE Committee:

- a Sustainability Management Committee, comprised of senior leaders and heads of business units from across the company, that provides strategic direction on sustainability-related matters and fosters cross-functional collaboration across the organization
- Safety and TOMS Advisory Committee (STAC), comprised of senior project and operations leaders, oversees governance and decision-making for TOMS and safety initiatives, while assuming an enterprise-wide role to oversee and guide health, safety, environment and operational integrity. In 2025, governance accountability transitioned from the Operating Committee to the relevant business leadership teams, business unit-specific operating committees and STAC.

Health, safety and asset integrity

The safety of our employees, contractors and the public, the integrity of our pipelines and our power and energy solutions infrastructure, are a top priority. All assets are designed, constructed, commissioned, operated and maintained with full consideration given to safety and integrity and are placed in service only after all necessary requirements, both regulatory and internal, have been satisfied.

In 2025, we spent approximately $2.0 billion (2024 – $2.0 billion) for pipeline integrity on the natural gas pipelines we operate, which includes expenditures related to our modernization program within our U.S. Natural Gas Pipelines business. Pipeline integrity spending will fluctuate based on the results of on-going risk assessments conducted on our pipeline systems and evaluations of information obtained from recent inspections, incidents and maintenance activities.

Under the approved regulatory models in Canada, non-capital pipeline integrity expenditures on CER-regulated natural gas pipelines are generally treated on a flow-through basis and, as a result, fluctuations in these expenditures generally have no impact on our earnings. Non-capital pipeline integrity expenditures on our U.S. natural gas pipelines are primarily treated as operations and maintenance expenditures and are typically recoverable through tolls approved by FERC. Under regulatory rules in Mexico, non-capital pipeline integrity expenditures and those under lease accounting are treated primarily as operating and maintenance expenses and are generally recovered through our tolls.

Spending associated with process safety and integrity is used to minimize risk to employees, contractors, the public, equipment and the surrounding environment and also prevent disruptions to serving the energy needs of our customers.

As described in the Risk oversight and enterprise risk management section above, we have a set of procedures in place to manage our response to natural disasters, which include catastrophic events such as forest fires, tornadoes, earthquakes, floods, volcanic eruptions and hurricanes. The procedures, which are included in our Emergency, Business Continuity and Security element of TOMS, are designed to help protect the health and safety of our employees and contractors, minimize risk to the public and limit the potential for adverse effects on the environment. We are committed to protecting the health and safety of all individuals involved in our activities. Occupational health, safety and industrial hygiene provides comprehensive strategies for health promotion and protection. We are committed to delivering effective programs that:
- reduce the human and financial impact of illness and injury
- ensure fitness for work
- strengthen worker resiliency
- build organizational capacity by focusing on individual wellbeing, health education, leader support and improved working conditions to sustain a productive workforce
- increase mental wellbeing awareness, provide various health and wellness supports and training to employees and leaders, measure the success of programs and improve psychological safety
- foster a strong safety culture by building human and organizational performance to strengthen our cultural defenses and develop error-tolerant systems to better protect our people.

Environmental risk, compliance and liabilities

Through the implementation of TOMS, TC Energy proactively and systematically manages environmental hazards and risks throughout the lifecycle of our assets. Project plans are communicated with stakeholders and Indigenous communities, as applicable and engagement with these groups informs the environmental assessments and protection plans. Project environmental assessments include field studies that examine existing natural resources, biodiversity and land use along our proposed project footprint, such as vegetation, soils, wildlife, water resources, wetland and protected areas. We consider the information collected during environmental assessments and where sensitive habitats or areas of high biodiversity value are identified, we apply the biodiversity mitigation hierarchy and avoid those areas, as practicable. Where those areas cannot be avoided, we minimize our disturbance, restore and reclaim the disturbed area and provide offsets where required. To conserve and protect the environment during construction, information gathered for an environmental impact assessment is used to develop project-specific environmental protection plans. Whenever the potential exists for a proposed facility or pipeline to interact with water resources, we conduct evaluations to understand the full nature and extent of the interactions. When we temporarily use water to test the integrity of our pipelines, we adhere to strict regulatory requirements and ensure water meets applicable water quality standards before it is discharged or disposed of and when our construction activities involve crossing waterbodies, we implement protection measures to avoid or minimize potential adverse effects.

Our primary sources of risk related to the environment include:
- evolving regulations and compliance requirements, alongside rising costs associated with environmental impacts
- product releases with potential environmental impact
- use, storage and disposal of chemicals and hazardous materials
- natural disasters and other catastrophic events, including those related to climate change, which may impact our operations.

Our assets are subject to federal, state, provincial and local environmental statutes and regulations governing environmental protection, including air and GHG emissions, water quality, species at risk, wastewater discharges and waste management. Operating our assets requires obtaining and complying with a wide variety of environmental registrations, licenses, permits and other approvals and requirements. Failure to comply could result in administrative, civil or criminal penalties, remedial requirements, or orders affecting future operations.

TOMS includes requirements for us to continually monitor our facilities for compliance with all material legal and regulatory environmental requirements across all jurisdictions where we operate. We also comply with all material legal and regulatory permitting requirements in our project routing and development. We routinely monitor proposed changes to environmental policy, legislation and regulation. Where the risks are uncertain or have the potential to affect our ability to effectively operate our business, we comment on proposals independently or through industry associations.

We are not aware of any material outstanding orders, claims or lawsuits against us related to releasing or discharging any material into the environment.

Compliance obligations can result in significant costs associated with installing and maintaining pollution controls, fines and penalties resulting from any failure to comply and potential limitations on operations. Remediation obligations can result in significant costs associated with the investigation and remediation of contaminated properties and with damage claims arising from the contamination of properties.

The timing and complete extent of future expenditures related to environmental matters is difficult to estimate accurately because:
- environmental laws and regulations and their interpretations and enforcement change
- new claims can be brought against our existing or discontinued assets
- our pollution control and clean-up cost estimates may change, especially when our current estimates are based on preliminary site investigations or agreements
- new contaminated sites may be found or what we know about existing sites could change
- where there is potentially more than one responsible party involved in litigation, we cannot estimate our joint and several liability with certainty.

At December 31, 2025, accruals related to these obligations totaled $6 million (2024 – $8 million) representing the estimated amount we will need to manage our currently known material environmental liabilities. We believe we have considered all necessary contingencies and established appropriate reserves for environmental liabilities; however, a risk exists that unforeseen matters may arise requiring us to set aside additional amounts. We adjust reserves regularly to account for changes in liabilities.

Climate policy and related regulation

We own assets and have business interests in a number of regions subject to GHG emissions regulations, including GHG emissions management and carbon pricing policies. In 2025, we incurred $194 million (2024 – $141 million) of expenses under existing carbon pricing programs. Across North America, there are a variety of new and evolving climate policy developments at the federal, regional, state and provincial levels. We actively monitor, participate in the regulatory review process as appropriate and submit formal comments to regulators as initiatives are undertaken and as policies are implemented. We support transparent, investment-conducive climate policies that promote environmentally and economically responsible natural resource development through market-driven and economically efficient outcomes. Our assets in certain geographies are currently subject to GHG regulations. While near-term government policy objectives may influence the pace of GHG regulations, we expect that the number of our assets subject to GHG regulations will continue to increase over time and across our footprint. Changes in regulations may often result in higher operating costs, other expenses or capital expenditures, which are generally recoverable through established cost-recovery mechanisms.

Jurisdictional policies

This section describes the most relevant existing and emerging policies affecting our business, emphasizing legislative and regulatory impacts.

In the U.S., we have seen significant policy shifts under the current administration. In January 2025, several Executive Orders directed agency heads to use all available legal authority to enhance U.S. energy production, transportation and consumption, and to focus on energy production and utilization ("energy dominance"). Additionally, in March 2025, the U.S. Environmental Protection Agency (USEPA) outlined a list of plans, including changes to some USEPA programs, and the intent for administrative reconsideration of many rules promulgated under the previous administration that have now started to advance through the regulatory process. Substantial uncertainty exists with respect to future implementation of these rules and the scope of the USEPA's jurisdiction more generally. Depending upon the outcome of certain rulemakings and associated litigation challenging new rules, TC Energy could face increased project delays. We continue to monitor these potential regulatory changes to determine our compliance obligations and potential costs.

Existing policies

- **Carbon pricing policies** (*multi-jurisdictional*): While carbon pricing exists in several jurisdictions where we operate, its applicability to our assets and associated compliance costs vary substantially. Carbon pricing policies with significant impact on our business include the following:
  - Canada – Alberta's Technology Innovation and Emissions Reduction (TIER) program represents our largest compliance costs in Canada. For our regulated Canadian natural gas pipelines within the province, we recover these costs through tolls. For our Power and Energy Solutions assets, we recover a portion of these costs through market pricing and hedging activities
  - U.S. – certain GTN compressor facilities are subject to the Washington Cap-and-Invest Program. GTN's compliance costs are driven by total facility emissions, and GTN is authorized to recover these costs through its rates over time
- **Clean Electricity Regulations** (*Canada*): In 2024, Environment and Climate Change Canada (ECCC) published the final Clean Electricity Regulations (CERs) to transition Canada's electricity system to net-zero electricity by 2050. The CERs mandate an annual GHG emissions limit based on 65 tonnes CO_2/GWh for fossil fuel power generation units with a capacity of 25 MW or more starting in 2035 and zero tonnes CO_2/GWh in 2050. Concerns persist on the CERs' potential effect on energy affordability and reliability in certain provinces given the regulations limited compliance flexibilities. We continue to evaluate the operational and financial impact on TC Energy cogeneration plants. The Canada-Alberta Memorandum of Understanding (MOU), signed in November 2025, signals the CERs would be suspended in Alberta pending a new carbon pricing agreement. If a regulatory exemption is reached for the province, this would remove the requirement to comply with the CERs for most of TC Energy's cogeneration facilities
- **Endangerment Finding** (*U.S.*): In July 2025, the USEPA released a proposal to rescind the 2009 Endangerment Finding (the Finding), which found that GHG emissions pose a threat to public health and welfare. The Finding has been the basis for subsequent GHG regulations. While rescinding the Finding would not automatically invalidate existing GHG regulations for the oil and gas sector, the USEPA has indicated that it plans to separately review related current standards. TC Energy has consistently complied with various regulations stemming from the Finding. We continue to monitor the USEPA's proposed regulatory changes; however, the impacts of these proposed changes cannot be determined at this time
- **Greenhouse Gas Reporting Program (GHGRP)** (*U.S.*): In 2024, the USEPA finalized changes to the GHGRP for how oil and gas sources tally and report their methane emissions (Subpart W). These changes add new reporting sources, modify calculation and reporting methodologies, and drive more granular data collection. Subsequently, in September 2025, USEPA issued a draft rule that announced it found no obligation under the Clean Air Act to collect GHG data and no statutory benefit. In the proposal, USEPA proposes to eliminate reporting obligations for all GHGRP subparts, except Subpart W (non-combustion GHG emissions from the Petroleum & Natural Gas Systems), which would be suspended until the Reporting Year 2034. The potential elimination or significant overhaul of the GHGRP could potentially have indirect implications for state-level reporting frameworks, voluntary industry reporting and compliance strategies and overall transparency of emissions data. Certain states may elect to implement GHG reporting programs in the absence of a federal framework, which could increase administrative burden and complicate cross-jurisdictional reporting for our industry. TC Energy supported industry group comments advocating for retention of the GHGRP. Additionally, in November 2024, USEPA finalized its rule to implement the Inflation Reduction Act's Waste Emission Charge, which would apply a fee to certain oil and gas facilities that report methane emissions of more than 25,000 metric tons of carbon dioxide equivalent per year to the GHGRP. However, in March 2025, Congress prohibited USEPA from collecting the Waste Emissions Charge until 2034. As a result of the pending changes to the GHGRP, substantial uncertainty exists with respect to future implementation of the Waste Emissions Charge

- **Good Neighbor Rule** (*U.S.*): The USEPA "Good Neighbor Rule" (the Rule) as finalized in March 2023, set new limits for emissions of nitrogen oxides (NOx) from reciprocating internal combustion engines by May 2026. The Rule was stayed in its entirety by the U.S. Supreme Court in June 2024 pending a complete review by the U.S. Circuit Court of Appeals for the D.C. Circuit (the "D.C. Circuit Court"). In March 2025, the USEPA Administrator announced the intention to reconsider numerous pending, proposed and final rules and policies, including "ending" the Rule. The USEPA subsequently stated it plans to reconsider the Rule and conduct a new rulemaking process in 2026. As a result, the D.C. Circuit has placed the litigation challenging the existing Rule in abeyance to allow the USEPA to reconsider and propose the new rule. On January 28, 2026, the USEPA announced the first of a two-step plan to reconsider the Rule, issuing a proposal to reverse prior State Implementation Plan disapprovals in the eight states that were subject to the Rule. If finalized as proposed, the Rule would no longer apply in several states where TC Energy operates assets subject to the Rule. The USEPA indicated that it will take secondary action in the near term to address the states that remain subject to the Rule. We continue to monitor and assess the USEPA's proposed regulatory changes
- **Methane-specific regulations** (*multi-jurisdictional*): In all three countries where TC Energy operates, there are regulations to reduce methane emissions from the oil and gas industry. Though requirements vary by jurisdiction, they generally focus on eliminating fugitive emissions through leak detection and repair programs and reducing vented emissions from equipment. The regulations in each country is discussed below:
  - Canada – The ECCC Regulations Respecting Reduction in the Release of Methane and Certain Volatile Organic Compounds took effect in 2020 and aimed to reduce the oil and gas sector's methane emission by 40 to 45 per cent below 2012 levels by 2025. Several provinces enacted their own methane regulations that took the place of the federal regulations for provincially regulated assets through equivalency agreements. Our Canadian natural gas pipeline assets are subject to either the federal or British Columbia requirements, while our Alberta natural gas storage assets are subject to the Alberta requirements. In December 2025, ECCC published amendments to strengthen these regulations. This is part of Canada's newest commitment to reduce the oil and gas sector methane emissions by at least 75 per cent below 2012 levels by 2030. The amendments introduce a risk-based approach for the detection and repair of fugitive emissions, prohibit all venting with specific exceptions, and offer an alternative performance-based approach using continuous monitoring. The amendments take effect on January 1, 2028, with phased requirements through 2030. While our Canadian natural gas pipeline assets have a mature leak detection and repair program and vent management approach to meet current regulations, compliance with these amendments will impose additional costs to our operations. We will continue to refine our internal emissions management strategies and update our compliance plans for our Canadian natural gas pipeline assets to align with the regulatory changes
  - U.S. – In 2023, the USEPA finalized a rule that amended and supplemented the New Source Performance Standards – Subpart OOOO series of volatile organic compound and methane emissions regulations for the oil and natural gas industry. The rule, collectively referred to as the "Methane Rule," set performance standards for new, modified, or reconstructed sources after December 6, 2022 (OOOOb) and established emission guidelines (EGs) for existing sources prior to December 6, 2022 (OOOOc). Affected U.S. natural gas compressor stations would be required to comply with the Methane Rule, and the costs of compliance are anticipated to be incorporated into new and modified facilities moving forward. The OOOOc standards would apply to a larger number of existing facilities, but impacts will be subject to the requirements of state EG proposals and actual compliance deadlines, which will vary based on state and/or location and have not yet been issued. In July 2025, USEPA issued an interim final rule (IFR) that extends several compliance deadlines under both OOOOb and OOOOc. The IFR also indicates that the USEPA may introduce further substantive changes to the Methane Rule through a separate reconsideration process. These extensions give operators and states more practical timelines for associated implementation and planning but also provide USEPA with time to proceed with announced plans for reconsideration of the Methane Rule. Certain states, such as New York, Pennsylvania, Maryland and California, have independently enacted their own methane emissions regulations. TC Energy is closely monitoring these developments as applicable to our business
  - Mexico – In 2018, the Agencia de Seguridad, Energía y Ambiente (ASEA) released the Guidelines for the Prevention and Control of Methane Emissions from the Hydrocarbon Sector to reduce the sector's methane emissions by 40 to 45 per cent by 2025. Per the guidelines' requirements, TC Energy developed and has implemented a Program for the Comprehensive Prevention and Control of Methane Emissions (PPCIEM) for our Mexican facilities since 2020

- **Onshore Natural Gas Pipelines Standard** (*Mexico*): In September 2025, ASEA replaced NOM-007-ASEA-2016 with NOM-020-ASEA-2024 to regulate the design, construction, operation and maintenance of onshore natural gas transmission pipelines. The standard, which will take effect February 28, 2026, adds incremental requirements with respect to operations, maintenance, inspections, documentation and audits to renew and maintain permits. We are currently updating our pipeline design and construction processes accordingly. We do not anticipate this standard to have a material impact on our business in Mexico
- **Sustainability-related disclosure requirements** (*multi-jurisdictional*): Various sustainability disclosure requirements (including climate-related topics) are being issued in jurisdictions in which we operate. We continue to monitor these developments and progress our sustainability-related disclosures to reflect new and anticipated requirements. Our enterprise-wide sustainability-related disclosures, including a dedicated Climate-related disclosures section, can be found in our annual Report on Sustainability
  - U.S. – California's senate bill (SB) -253 and SB-261 require certain U.S. companies doing business in California to disclose their GHG emissions and climate-related financial risks, respectively. Entities within the scope of SB-261 must prepare a climate-related financial risk report by January 1, 2026; however, enforcement of SB-261 has been halted while litigation is ongoing in federal court. Applicability to TC Energy is under evaluation
  - Mexico – the Normas de Información de Sostenibilidad (NIS) requires the disclosure of 30 sustainability indicators across environmental, social and governance topics for fiscal years beginning on or after January 1, 2025. These requirements will apply to certain TC Energy Mexican entities as part of compliance with financial standards.

Anticipated policies

- **Carbon Pricing** (*Canada*): In December 2025, ECCC released a discussion paper on potential updates to strengthen the federal carbon pricing benchmark on industrial emissions, which sets the minimum requirements for provincial systems. In general, these systems require regulated facilities to reduce their emissions below an intensity baseline which leads to credit generation or compliance obligations. The proposed updates include changes to coverage and scope, certain compliance pathways and public reporting requirements. They are intended to ensure industrial carbon pricing systems are more consistent, efficient and effective across the country. TC Energy currently operates under several carbon pricing systems subject to the federal backstop. We will monitor these developments, evaluate potential impacts and engage with ECCC, as appropriate
- **New Energy Policy Considerations** (*Mexico*): In late 2025, Mexico published the New Energy Policy Considerations as part of its broader energy policy framework, which includes the Energy Sector Program 2025-2030 (PROSENER) and other official documents. The energy policy framework influences the country's implementation of climate policies, long-term view of natural gas, and integration of social objectives. It also signals the development of additional regulations. PROSENER specifically proposes additional emission reductions (including methane) through greater energy efficiency, technological innovation, and the construction and modernization of new energy infrastructure. We will continue monitoring these policy developments and provide feedback to the respective government departments, as appropriate
- **Oil and Gas Emissions Cap** (*Canada*): In 2024, ECCC published the draft Oil and Gas Sector Greenhouse Gas Emissions Cap Regulations. The draft regulations introduce a cap-and-trade system as of 2030 to reduce GHG emissions from the oil and gas sector, covering upstream activities and LNG production. Although transmission pipelines are excluded from the draft regulations, there is a possibility of cascading effects and unintended consequences to our Canadian natural gas pipelines business. The draft regulations were set to be finalized in 2025, but under the Canada-Alberta MOU signed in November 2025, the Government of Canada has committed to not implementing them
- **TIER Updates** (*Alberta, Canada*): In December 2025, the Government of Alberta issued an Order in Council introducing an additional compliance pathway that will recognize certain on-site emissions reduction investments for up to 90 per cent of compliance obligations and allowing facilities that are below the regulatory emissions threshold and currently participate in the TIER emission program to opt-out of paying into the TIER fund or retire TIER compliance instruments. The Canada-Alberta MOU signed in November 2025 signals additional changes may be proposed to TIER's carbon price, price escalation, and performance benchmarks. Since these changes are likely to impact the carbon credit market, their effects may have different impacts on our Alberta-based Canadian natural gas pipelines and Power and Energy Solutions assets. We will continue to monitor and evaluate the operational and financial impacts as details of the new carbon pricing agreement with the Government of Canada are made available.

Financial risks

We are exposed to various financial risks and have strategies, policies and limits in place to manage the impact of these risks on our earnings, cash flows and, ultimately, shareholder value.

Risk management strategies, policies and limits are designed to ensure our risks and related exposures are in line with our business objectives and risk tolerance. Our risks are managed within limits that are established by our Board of Directors, implemented by senior management and monitored by our risk management, internal audit and business segment groups. Our Board of Directors' Audit Committee oversees how management monitors compliance with risk management policies and procedures and oversees management's review of the adequacy of the risk management framework.

Market risk

We construct and invest in energy infrastructure projects, purchase and sell commodities, issue short- and long-term debt, including amounts in foreign currencies and invest in foreign operations. Certain of these activities expose us to market risk from changes in commodity prices, foreign exchange rates and interest rates, which may affect our earnings, cash flows and the value of our financial assets and liabilities. We assess contracts used to manage market risk to determine whether all, or a portion, meet the definition of a derivative.

Derivative contracts used to assist in managing exposure to market risk may include the following:

- forwards and futures contracts – agreements to purchase or sell a specific financial instrument or commodity at a specified price and date in the future
- swaps – agreements between two parties to exchange streams of payments over time according to specified terms
- options – agreements that convey the right, but not the obligation of the purchaser, to buy or sell a specific amount of a financial instrument or commodity at a fixed price, either at a fixed date or at any time within a specified period.

Commodity price risk

The following strategies may be used to manage our exposure to market risk resulting from commodity price risk management activities in our non-regulated businesses:

- in our natural gas marketing business, we enter into natural gas transportation and storage contracts, as well as natural gas purchase and sale agreements. We manage our exposure on these contracts using financial instruments and hedging activities to offset market price volatility
- in our power business, we manage the exposure to fluctuating commodity prices through long-term contracts and hedging activities including selling and purchasing electricity and natural gas in forward markets
- in our non-regulated natural gas storage business, our exposure to seasonal natural gas price spreads is managed with a portfolio of third-party storage capacity contracts and through offsetting purchases and sales of natural gas in forward markets to lock in future positive margins.

Lower natural gas or electricity prices could lead to reduced investment in the development, expansion and production of these commodities. A reduction in the demand for these commodities could negatively impact opportunities to expand our asset base and/or re-contract with our shippers and customers as contractual agreements expire.

Interest rate risk

We utilize both short- and long-term debt to finance our operations which exposes us to interest rate risk. We typically pay fixed rates of interest on our long-term debt and floating rates on short-term debt including our commercial paper programs and amounts drawn on our credit facilities. A small portion of our long-term debt bears interest at floating rates. In addition, we are exposed to interest rate risk on financial instruments and contractual obligations containing variable interest rate components. We actively manage our interest rate risk using interest rate derivatives.

Foreign exchange risk

Certain of our businesses generate all or most of their earnings in U.S. dollars and since we report our financial results in Canadian dollars, changes in the value of the U.S. dollar against the Canadian dollar directly affect our comparable EBITDA and may also impact comparable earnings.

A portion of our Mexico Natural Gas Pipelines' monetary assets and liabilities are peso-denominated, while our Mexico operations' financial results are denominated in U.S. dollars. Therefore, changes in the value of the Mexican peso against the U.S. dollar can affect our comparable earnings. In addition, foreign exchange gains or losses calculated for Mexico income tax purposes on the revaluation of U.S. dollar-denominated monetary assets and liabilities result in a peso-denominated income tax exposure for these entities, leading to fluctuations in Income (loss) from equity investments and Income tax expense (recovery) in the Consolidated statement of income.

We actively manage a portion of our foreign exchange risk using foreign exchange derivatives. Refer to the Foreign exchange section for additional information.

We hedge a portion of our net investment in foreign operations (on an after-tax basis) with U.S. dollar-denominated debt and cross-currency interest rate swaps as appropriate.

Counterparty credit risk

We have exposure to counterparty credit risk in a number of areas including:

- cash and cash equivalents
- accounts receivable
- available-for-sale assets
- fair value of derivative assets
- net investment in leases and certain contract assets in Mexico.

At times, our counterparties may endure financial challenges resulting from commodity price and market volatility, economic instability and political or regulatory changes. In addition to actively monitoring these situations, there are a number of factors that reduce our counterparty credit risk exposure in the event of default, including:

- contractual rights and remedies together with the utilization of contractually-based financial assurances
- current regulatory frameworks governing certain of our operations
- the competitive position of our assets and the demand for our services
- potential recovery of unpaid amounts through bankruptcy and similar proceedings.

We review financial assets carried at amortized cost for impairment using the lifetime expected loss of the financial asset at initial recognition and throughout the life of the financial asset. We use historical credit loss and recovery data, adjusted for our judgment regarding current economic and credit conditions, along with reasonable and supportable forecasts to determine if any impairment should be recognized in Plant operating costs and other. At December 31, 2025 and 2024, we had no significant credit risk concentrations, with the exception of the CFE, which represents approximately 33 per cent of gross exposure. Gross exposure is measured as the unmitigated full-term contract revenue exposure discounted in accordance with each contract's discount rate, as applicable. At this time, there were no significant amounts past due or impaired. We recorded a pre-tax expense of $83 million for the year ended December 31, 2025 on the expected credit loss provision before tax recognized on TGNH net investment in leases and certain contract assets in Mexico (2024 – $22 million recovery). During 2025, we completed the Southeast Gateway pipeline and recognized a net investment in sales-type lease. Other than the expected credit loss provision noted above, we had no significant credit losses at December 31, 2025 and 2024. Refer to Note 27, Risk management and financial instruments, of our 2025 Consolidated financial statements for additional information.

We have significant credit and performance exposure to financial institutions that hold cash deposits and provide committed credit lines and letters of credit that help manage our exposure to counterparties and provide liquidity in commodity, foreign exchange and interest rate derivative markets. Our portfolio of financial sector exposure consists primarily of highly-rated investment grade, systemically important financial institutions.

Liquidity risk

Liquidity risk is the risk that we will not be able to meet our financial obligations as they come due. We manage our liquidity risk by continuously forecasting our cash flows and ensuring we have adequate cash balances, cash flows from operations, committed and demand credit facilities and access to capital markets to meet our operating, financing and capital expenditure obligations under both normal and stressed economic conditions. Refer to the Financial Condition section for additional information.

Legal proceedings

TC Energy and its subsidiaries are subject to various legal proceedings, arbitrations and actions arising in the normal course of business. We assess all legal matters on an ongoing basis, including those of our equity investments to determine if they meet the requirements for disclosure or accrual of a contingent loss. Refer to Note 30, Commitments, contingencies and guarantees, of our 2025 Consolidated financial statements for additional information.

CONTROLS AND PROCEDURES

We meet Canadian and U.S. regulatory requirements for disclosure controls and procedures, internal control over financial reporting and related CEO and CFO certifications.

Disclosure controls and procedures

Under the supervision and with the participation of management, including our President and CEO and our CFO, we carried out quarterly evaluations of the effectiveness of our disclosure controls and procedures, including for the year ended December 31, 2025, as required by the Canadian securities regulatory authorities and by the SEC. Based on this evaluation, our President and CEO and our CFO have concluded that the disclosure controls and procedures are effective in that they are designed to ensure that the information we are required to disclose in reports we file with or send to securities regulatory authorities is recorded, processed, summarized and reported accurately within the time periods specified under Canadian and U.S. securities laws.

Management's report on internal control over financial reporting

We are responsible for establishing and maintaining adequate internal control over financial reporting, which is a process designed by, or under the supervision of, our President and CEO and our CFO and effected by our Board of Directors, management and other personnel, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with GAAP.

Under the supervision and with the participation of management, including our President and CEO and our CFO, an evaluation of the effectiveness of the internal control over financial reporting was conducted as of December 31, 2025, based on the criteria described in "Internal Control – Integrated Framework" issued in 2013 by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, management determined that, as of December 31, 2025, the internal control over financial reporting was effective.

Our internal control over financial reporting as of December 31, 2025 has been audited by KPMG LLP, an independent registered public accounting firm, as stated in their attestation report which is included in our 2025 Consolidated financial statements.

CEO and CFO certifications

Our President and CEO and our CFO have attested to the quality of the public disclosure in our fiscal 2025 reports filed with Canadian securities regulators and the SEC and have filed certifications with them.

Changes in internal control over financial reporting

There were no changes during the year covered by this annual report that had or are reasonably likely to have a material impact on our internal control over financial reporting.

CRITICAL ACCOUNTING ESTIMATES

In preparing our Consolidated financial statements, we are required to make estimates and assumptions that affect both the amount and timing of recording assets, liabilities, revenues and expenses since the determination of these items may be dependent on future events. We use the most current information available and exercise careful judgment in making these estimates and assumptions.

Certain estimates and judgments have a material impact where the assumptions underlying these accounting estimates relate to matters that are highly uncertain at the time the estimate or judgment is made or are subjective. Refer to Note 2, Accounting policies, of our 2025 Consolidated financial statements for additional information.

Sales-type leases

We determined that the Southeast Gateway pipeline is classified as a sales-type lease between TGNH and the CFE. Under a sales-type lease, we derecognize the underlying asset and record a net investment in lease equal to the present value of both the future lease payments and the estimated residual value of the leased asset.

To record the net investment in lease, we were required to prepare an estimate of the fair value of the Southeast Gateway pipeline on the lease commencement date. The TGNH pipelines, which includes the Southeast Gateway pipeline, are rate-regulated and the tolls are designed to recover the cost of providing service. On this basis, we applied judgment to determine that, at the inception of the lease arrangement, the fair value of the underlying assets approximated the carrying value and the residual value approximated the remaining carrying value at the end of the lease term. We estimated that if the assets were purchased at their carrying value, they would yield a return to the purchaser that is in line with current market participant expectations.

Impairment of goodwill

We test goodwill for impairment annually or more frequently if events or changes in circumstances lead us to believe it might be impaired. We can initially assess qualitative factors which include, but are not limited to, macroeconomic conditions, industry and market considerations, cost factors, historical and forecasted financial results, or events specific to that reporting unit. If we conclude that it is not more likely than not that the fair value of the reporting unit is greater than its carrying value, we will then perform a quantitative goodwill impairment test. We can elect to proceed directly to the quantitative goodwill impairment test for any reporting unit. If the quantitative goodwill impairment test is performed, we compare the fair value of the reporting unit to its carrying value, including its goodwill. If the carrying value of a reporting unit exceeds its fair value, goodwill impairment is measured at the amount by which the reporting unit's carrying value exceeds its fair value.

When a portion of a reporting unit that constitutes a business is disposed, goodwill associated with that business is included in the carrying amount of the business in determining the gain or loss on disposal. The amount of goodwill disposed is determined based on the relative fair values of the business to be disposed and the portion of the reporting unit that will be retained.

We determine the fair value of a reporting unit based on our projections of future cash flows, which involves making estimates and assumptions about transportation rates, market supply and demand, growth opportunities, output levels, competition from other companies, operating costs, regulatory changes, discount rates and earnings and other multiples.

The estimated fair value in excess of the carrying value was less than 10 per cent on our Great Lakes reporting unit at the date of our last quantitative goodwill impairment test. Any future reductions in cash flow forecasts or adverse changes in other key assumptions could result in a future impairment of our goodwill balance.

Qualitative goodwill impairment indicators

As part of the annual goodwill impairment assessment at December 31, 2025, we evaluated qualitative factors impacting the fair value of the underlying reporting units for all reporting units other than the Columbia reporting unit, which is described below. It was determined that it was more likely than not that the fair value of these reporting units exceeded their carrying amounts, including goodwill.

Columbia

We elected to proceed directly to a quantitative annual impairment test at December 31, 2025 for the $10,082 million (US$7,351 million) of goodwill related to the Columbia reporting unit following the Columbia Gas Settlement. To determine fair value, we used a discounted cash flow model incorporating projections of our future cash flows as well as a valuation multiple and applied a risk-adjusted discount rate which involved significant estimates and judgments. The fair value measurement is classified as Level III in the fair value hierarchy. It was determined that the fair value of the Columbia reporting unit exceeded its carrying value, including goodwill, at December 31, 2025.

FINANCIAL INSTRUMENTS

With the exception of Long-term debt and Junior subordinated notes, our derivative and non-derivative financial instruments are recorded on the balance sheet at fair value unless they were entered into and continue to be held for the purpose of receipt or delivery in accordance with our normal purchase and sales exemptions and are documented as such. In addition, fair value accounting is not required for other financial instruments that qualify for certain accounting exemptions.

Derivative instruments

We use derivative instruments to reduce volatility associated with fluctuations in commodity prices, interest rates and foreign exchange rates. Derivative instruments, including those that qualify and are designated for hedge accounting treatment, are recorded at fair value.

The majority of derivative instruments that are not designated or do not qualify for hedge accounting treatment have been entered into as economic hedges to manage our exposure to market risk and are classified as held-for-trading. Changes in the fair value of held-for-trading derivative instruments are recorded in net income in the period of change. This may expose us to increased variability in reported operating results since the fair value of the held-for-trading derivative instruments can fluctuate significantly from period to period.

The recognition of gains and losses on derivatives for Canadian natural gas regulated pipeline exposures is determined through the regulatory process. Gains and losses arising from changes in the fair value of derivatives accounted for as part of RRA, including those that qualify for hedge accounting treatment, are expected to be refunded or recovered through the tolls charged by us. As a result, these gains and losses are deferred as regulatory liabilities or regulatory assets and are refunded to or collected from the rate payers in subsequent years when the derivative settles.

Balance sheet presentation of derivative instruments

The balance sheet presentation of the fair value of derivative instruments is as follows:

at December 31 (millions of $)	**2025**	**2024**
Other current assets	**438**	347
Other long-term assets	**161**	122
Accounts payable and other	**(380)**	(507)
Other long-term liabilities	**(149)**	(209)
	70	(247)

Anticipated timing of settlement of derivative instruments

The anticipated timing of settlement of derivative instruments assumes constant commodity prices, interest rates and foreign exchange rates. Settlements will vary based on the actual value of these factors at the date of settlement.

at December 31, 2025 (millions of $)	**Total fair value**	**< 1 year**	**1 - 3 years**	**4 - 5 years**	**> 5 years**
Derivative instruments held for trading	116	41	64	31	(20)
Derivative instruments in hedging relationships	(46)	16	30	(76)	(16)
	70	57	94	(45)	(36)

Unrealized and realized gains (losses) on derivative instruments

The following summary does not include hedges of our net investment in foreign operations.

year ended December 31 (millions of $)	2025	2024	2023
Derivative Instruments Held for Trading[1]			
Unrealized gains (losses) in the year			
Commodities	**25**	(71)	132
Foreign exchange	**210**	(266)	246
Interest rate	**—**	(71)	—
Realized gains (losses) in the year			
Commodities	**(10)**	199	192
Foreign exchange	**142**	(152)	155
Interest rate	**8**	29	—
Derivative Instruments in Hedging Relationships[2]			
Realized gains (losses) in the year			
Commodities	**24**	33	(2)
Foreign exchange	**10**	—	—
Interest rate	**(30)**	(52)	(43)

1 Realized and unrealized gains (losses) on held-for-trading derivative instruments used to purchase and sell commodities are included on a net basis in Revenues in the Consolidated statement of income. Realized and unrealized gains (losses) on foreign exchange and interest rate held-for-trading derivative instruments are included on a net basis in Foreign exchange (gains) losses, net and Interest expense, respectively in the Consolidated statement of income.

2 In 2025, unrealized gains of $2 million were reclassified to Net Income (loss) from AOCI related to discontinued cash flow hedges (2024 – unrealized gains of $6 million; 2023 – nil).

For further details on our non-derivative and derivative financial instruments, including classification assumptions made in the calculation of fair value and additional discussion of exposure to risks and mitigation activities, refer to Note 27, Risk management and financial instruments, of our 2025 Consolidated financial statements.

RELATED PARTY TRANSACTIONS

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

Coastal GasLink LP

We hold a 35 per cent equity interest in Coastal GasLink LP and operate the Coastal GasLink pipeline.

We have a subordinated loan agreement with Coastal GasLink LP under which we advance non-revolving interest-bearing loans subject to floating market-based rates. In December 2024, following the commercial in-service of the pipeline, Coastal GasLink LP repaid the $3,147 million balance outstanding to TC Energy under the subordinated loan agreement. Unused committed capacity available for use by Coastal GasLink LP at December 31, 2025 was $163 million (December 31, 2024 – $228 million).

We also have a subordinated demand revolving credit facility agreement with Coastal GasLink LP to provide additional short-term liquidity and funding flexibility to projects under construction.

Sur de Texas

We hold a 60 per cent equity interest in a joint venture with IEnova to own the Sur de Texas pipeline, operated by TC Energy. On December 15, 2025, TC Energía Mexicana, S. de R.L. de C.V. (TCEM) entered into a subordinated demand revolving credit facility to borrow funds from the joint venture at a floating interest rate. The facility has a capacity of US$270 million, maturing in December 2028. At December 31, 2025, the unused capacity available for use by TCEM was $259 million (US$189 million) and the outstanding balance of the loan was $111 million (US$81 million).

ACCOUNTING CHANGES

For a description of our significant accounting policies and a summary of changes in accounting policies and standards impacting our business, refer to Note 2, Accounting policies, and Note 3, Accounting changes, of our 2025 Consolidated financial statements.

QUARTERLY RESULTS

Selected quarterly consolidated financial data

2025 (millions of $, except per share amounts)	Fourth	Third	Second	First
Revenues from continuing operations	**4,168**	**3,704**	**3,744**	**3,623**
Net income (loss) attributable to common shares	**980**	**609**	**833**	**978**
from continuing operations	959	813	862	978
from discontinued operations	21	(204)	(29)	—
Comparable earnings[1]	**1,018**	**805**	**848**	**983**
from continuing operations	1,018	805	848	983
from discontinued operations	—	—	—	—
Share statistics:				
Net income (loss) per common share – basic	**$0.94**	**$0.58**	**$0.80**	**$0.94**
from continuing operations	$0.92	$0.78	$0.83	$0.94
from discontinued operations	$0.02	($0.20)	($0.03)	—
Comparable earnings per common share[1]	**$0.98**	**$0.77**	**$0.82**	**$0.95**
from continuing operations	$0.98	$0.77	$0.82	$0.95
from discontinued operations	—	—	—	—
Dividends declared per common share	**$0.85**	**$0.85**	**$0.85**	**$0.85**

1 Additional information on the most directly comparable GAAP measure can be found on page 22.

2024 (millions of $, except per share amounts)	Fourth	Third	Second	First
Revenues from continuing operations	3,577	3,358	3,327	3,509
Net income (loss) attributable to common shares	971	1,457	963	1,203
from continuing operations	1,069	1,338	804	988
from discontinued operations[1]	(98)	119	159	215
Comparable earnings[2]	1,094	1,074	978	1,284
from continuing operations	1,094	894	822	1,055
from discontinued operations[1]	—	180	156	229
Share statistics:				
Net income (loss) per common share – basic	$0.94	$1.40	$0.93	$1.16
from continuing operations	$1.03	$1.29	$0.78	$0.95
from discontinued operations[1]	($0.09)	$0.11	$0.15	$0.21
Comparable earnings per common share[2]	$1.05	$1.03	$0.94	$1.24
from continuing operations	$1.05	$0.86	$0.79	$1.02
from discontinued operations[1]	—	$0.17	$0.15	$0.22
Dividends declared per common share[3]	$0.8225	$0.96	$0.96	$0.96

1 Represents nine months of Liquids Pipelines earnings in 2024.
2 Additional information on the most directly comparable GAAP measure can be found on page 22.
3 Dividends declared in fourth quarter 2024 and thereafter reflect TC Energy's proportionate allocation following the Spinoff Transaction. Refer to the Discontinued operations section for additional information.

Factors affecting quarterly financial information by business segment

Quarter-over-quarter revenues and net income fluctuate for reasons that vary across our business segments. In addition to the factors below, our revenues and segmented earnings (losses) are impacted by fluctuations in foreign exchange rates, mainly related to our U.S. dollar-denominated operations and our peso-denominated exposure.

As discussed on page 10 of the About this document section, results of the Liquids Pipelines business were accounted for as a discontinued operation starting October 1, 2024. To allow for a meaningful comparison, discussions throughout the Quarterly results section are based on continuing operations unless otherwise noted. Refer to the Discontinued operations section for additional information.

In our Natural Gas Pipelines business, except for seasonal fluctuations in short-term throughput volumes on U.S. pipelines, quarter-over-quarter revenues and segmented earnings (losses) generally remain relatively stable during any fiscal year. Over the long term, however, they fluctuate because of:

- regulatory decisions
- negotiated settlements with customers
- newly constructed assets being placed in service
- acquisitions and divestitures
- natural gas marketing activities and commodity prices
- developments outside of the normal course of operations
- certain fair value adjustments
- provisions for expected credit losses on net investment in leases and certain contract assets in Mexico.

In Power and Energy Solutions, quarter-over-quarter revenues and segmented earnings are affected by:

- weather
- customer demand
- newly constructed assets being placed in service
- acquisitions and divestitures
- market prices for natural gas and power
- capacity prices and payments
- power marketing and trading activities
- planned and unplanned plant outages
- developments outside of the normal course of operations
- certain fair value adjustments.

Factors affecting financial information by quarter

We calculate comparable measures by adjusting certain GAAP measures for specific items we believe are significant but not reflective of our underlying operations in the period. Except as otherwise described herein, these comparable measures are calculated on a consistent basis from period to period and are adjusted for specific items in each period, as applicable. Refer to page 22 for more information on non-GAAP measures we use.

In fourth quarter 2025, comparable earnings from continuing operations also excluded:

- a pre-tax impairment charge of $110 million for certain Power and Energy Solutions projects following our decision to discontinue development along with updated forecast assumptions as we refocus our Power and Energy Solutions strategy
- pre-tax unrealized foreign exchange losses, net, of $47 million on the peso-denominated intercompany loan between TCPL and TGNH, net of non-controlling interest
- a pre-tax recovery of $4 million on the expected credit loss provision related to TGNH net investment in leases, net of non-controlling interest as well as certain contract assets in Mexico.

In third quarter 2025, comparable earnings from continuing operations also excluded:
- pre-tax unrealized foreign exchange gains, net, of $87 million on the peso-denominated intercompany loan between TCPL and TGNH, net of non-controlling interest
- a pre-tax recovery of $12 million on the expected credit loss provision related to TGNH net investment in leases, net of non-controlling interest as well as certain contract assets in Mexico.

In second quarter 2025, comparable earnings from continuing operations also excluded:
- pre-tax unrealized foreign exchange losses, net, of $132 million on the peso-denominated intercompany loan between TCPL and TGNH, net of non-controlling interest
- a pre-tax expense of $93 million on the expected credit loss provision related to TGNH net investment in leases, net of non-controlling interest as well as certain contract assets in Mexico.

In first quarter 2025, comparable earnings from continuing operations also excluded:
- pre-tax unrealized foreign exchange gains, net, of $3 million on the peso-denominated intercompany loan between TCPL and TGNH, net of non-controlling interest
- a pre-tax recovery of $2 million on the expected credit loss provision related to TGNH net investment in leases, net of non-controlling interest as well as certain contract assets in Mexico.

In fourth quarter 2024, comparable earnings from continuing operations also excluded:
- a pre-tax net gain on debt extinguishment of $228 million related to the purchase and cancellation of certain senior unsecured notes and medium term notes and the retirement of outstanding callable notes in October 2024
- pre-tax unrealized foreign exchange gains, net, of $143 million on the peso-denominated intercompany loan between TCPL and TGNH, net of non-controlling interest
- a pre-tax recovery of $3 million on the expected credit loss provision related to TGNH net investment in leases, net of non-controlling interest as well as certain contract assets in Mexico
- a deferred income tax expense of $96 million resulting from the revaluation of remaining deferred tax balances following the Spinoff Transaction
- a pre-tax impairment charge of $36 million for a Power and Energy Solutions project following our decision to discontinue development as we refocus our Power and Energy Solutions strategy
- a pre-tax expense of $9 million related to Focus Project costs.

In third quarter 2024, comparable earnings from continuing operations also excluded:
- a pre-tax gain of $572 million related to the sale of PNGTS which was completed on August 2024
- pre-tax unrealized foreign exchange losses, net, of $52 million on the peso-denominated intercompany loan between TCPL and TGNH, net of non-controlling interest
- a pre-tax expense of $5 million on the expected credit loss provision related to TGNH net investment in leases, net of non-controlling interest as well as certain contract assets in Mexico
- a pre-tax expense of $5 million related to Focus Project costs.

In second quarter 2024, comparable earnings from continuing operations also excluded:
- a pre-tax gain of $48 million related to the sale of non-core assets in U.S. Natural Gas Pipelines and Canadian Natural Gas Pipelines
- pre-tax unrealized foreign exchange losses, net of $3 million on the peso-denominated intercompany loan between TCPL and TGNH, net of non-controlling interest
- a pre-tax recovery of $3 million on the expected credit loss provision related to TGNH net investment in leases, net of non-controlling interest as well as certain contract assets in Mexico
- pre-tax costs of $10 million related to the NGTL System ownership transfer.

In first quarter 2024, comparable earnings from continuing operations also excluded:
- pre-tax unrealized foreign exchange gains, net of $55 million on the peso-denominated intercompany loan between TCPL and TGNH
- a pre-tax recovery of $21 million on the expected credit loss provision related to TGNH net investment in leases and certain contract assets in Mexico
- a pre-tax expense of $34 million related to a non-recurring third-party settlement
- a pre-tax expense of $10 million related to Focus Project costs.

FOURTH QUARTER 2025 HIGHLIGHTS

Consolidated results

three months ended December 31 (millions of $, except per share amounts)	2025	2024
Canadian Natural Gas Pipelines	**564**	506
U.S. Natural Gas Pipelines	**1,110**	918
Mexico Natural Gas Pipelines	**377**	214
Power and Energy Solutions	**136**	276
Corporate	**1**	(16)
Total segmented earnings (losses)	**2,188**	1,898
Interest expense	**(873)**	(679)
Allowance for funds used during construction	**36**	233
Foreign exchange gains (losses), net	**15**	(69)
Interest income and other	**58**	120
Income (loss) from continuing operations before income taxes	**1,424**	1,503
Income tax (expense) recovery from continuing operations	**(263)**	(223)
Net income (loss) from continuing operations	**1,161**	1,280
Net income (loss) from discontinued operations, net of tax	**21**	(98)
Net income (loss)	**1,182**	1,182
Net (income) loss attributable to non-controlling interests	**(167)**	(183)
Net income (loss) attributable to controlling interests	**1,015**	999
Preferred share dividends	**(35)**	(28)
Net income (loss) attributable to common shares	**980**	971
Net income (loss) per common share – basic	**$0.94**	$0.94
from continuing operations	**$0.92**	$1.03
from discontinued operations	**$0.02**	($0.09)

three months ended December 31 (millions of $)	2025	2024
Amounts attributable to common shares		
Net income (loss) from continuing operations	**1,161**	1,280
Net income (loss) attributable to non-controlling interest	**(167)**	(183)
Net income (loss) attributable to controlling interests from continuing operations	**994**	1,097
Preferred share dividends	**(35)**	(28)
Net income (loss) attributable to common shares from continuing operations	**959**	1,069
Net income (loss) from discontinued operations, net of tax	**21**	(98)
Net income (loss) attributable to common shares	**980**	971

Net income (loss) attributable to common shares from continuing operations decreased by $110 million or $0.11 per common share for the three months ended December 31, 2025 compared to the same period in 2024.

Reconciliation of net income (loss) attributable to common shares to comparable earnings - from continuing operations

three months ended December 31 (millions of $, except per share amounts)	2025	2024
Net income (loss) attributable to common shares from continuing operations	**959**	1,069
Specific items (pre tax):		
Power and Energy Solutions impairment charges	**110**	36
Foreign exchange (gains) losses, net – intercompany loan[1]	**47**	(143)
Expected credit loss provision on net investment in leases and certain contract assets in Mexico[2]	**(4)**	(3)
Net gain on debt extinguishment[3]	**—**	(228)
Focus Project costs[4]	**—**	9
Bruce Power unrealized fair value adjustments	**(4)**	(2)
Risk management activities[5]	**(87)**	301
Taxes on specific items[6]	**(3)**	55
Comparable earnings from continuing operations	**1,018**	1,094
Net income (loss) per common share from continuing operations	**$0.92**	$1.03
Specific items (net of tax)	**0.06**	0.02
Comparable earnings per common share from continuing operations	**$0.98**	$1.05

1 In 2023, TCPL and TGNH entered into an unsecured revolving credit facility. While the loan receivable and payable eliminate on consolidation, differences in each entity's reporting currency create a net income impact from revaluing and translating these balances into TC Energy's reporting currency. As the resulting unrealized foreign exchange gains and losses do not reflect amounts expected to be realized at settlement, we exclude them from comparable measures, net of non-controlling interest.

2 We have recognized an expected credit loss provision related to net investment in leases and certain contract assets in Mexico, which will fluctuate from period to period based on changing economic assumptions and forward-looking information. This provision is an estimate of losses that may occur over the duration of the TSA through 2055. This provision does not reflect losses or cash outflows that were incurred under this lease arrangement in the current period or from our underlying operations, and therefore, we have excluded any unrealized changes, net of non-controlling interest, from comparable measures. Refer to Note 27, Risk management and financial instruments, of our 2025 Consolidated financial statements for additional information.

3 In October 2024, TCPL commenced and completed our cash tender offers to purchase and cancel certain senior unsecured notes and medium term notes at a 7.73 per cent weighted average discount. In addition, we retired outstanding callable notes at par. These extinguishments of debt resulted in a pre-tax net gain of $228 million, primarily due to fair value discounts and unamortized debt issue costs. The net gain on debt extinguishment was recorded in Interest expense in the Consolidated statement of income. Refer to Note 19, Long-term debt, of our 2025 Consolidated financial statements for additional information.

4 In 2024 we recognized expenses related to the Focus Project for external consulting and severance, some of which are not recoverable through regulatory and commercial tolling structures.

5

three months ended December 31 (millions of $)	2025	2024
U.S. Natural Gas Pipelines	**(8)**	(37)
Canadian Power	**56**	17
U.S. Power	**5**	(2)
Natural Gas Storage	**(8)**	(20)
Interest rate	**1**	(71)
Foreign exchange	**41**	(188)
	87	(301)
Income tax attributable to risk management activities	**(21)**	72
Total unrealized gains (losses) from risk management activities	**66**	(229)

6 Refer to the Corporate - Financial results section for additional information.

Comparable EBITDA to comparable earnings - from continuing operations

Comparable EBITDA from continuing operations represents segmented earnings (losses) adjusted for the specific items described above and excludes charges for depreciation and amortization.

three months ended December 31 (millions of $, except per share amounts)	2025	2024
Comparable EBITDA from continuing operations		
Canadian Natural Gas Pipelines	**961**	851
U.S. Natural Gas Pipelines	**1,388**	1,200
Mexico Natural Gas Pipelines	**397**	234
Power and Energy Solutions	**217**	341
Corporate	**1**	(7)
Comparable EBITDA from continuing operations	**2,964**	2,619
Depreciation and amortization	**(719)**	(639)
Interest expense included in comparable earnings	**(874)**	(836)
Allowance for funds used during construction	**36**	233
Foreign exchange gains (losses), net included in comparable earnings	**29**	(44)
Interest income and other	**58**	120
Income tax (expense) recovery included in comparable earnings	**(266)**	(168)
Net (income) loss attributable to non-controlling interests included in comparable earnings	**(175)**	(163)
Preferred share dividends	**(35)**	(28)
Comparable earnings from continuing operations	**1,018**	1,094
Comparable earnings per common share from continuing operations	**$0.98**	$1.05

Comparable EBITDA from continuing operations

Fourth quarter 2025 versus fourth quarter 2024

Comparable EBITDA from continuing operations increased by $345 million for the three months ended December 31, 2025 compared to the same period in 2024 primarily due to the net result of the following:

- increased U.S. dollar-denominated EBITDA from U.S. Natural Gas Pipelines due to an increase in earnings from Columbia Gas as a result of higher transportation rates effective April 1, 2025, incremental earnings from projects placed in service, additional contract sales and higher realized earnings related to our U.S. natural gas marketing business
- increased U.S. dollar-denominated EBITDA from Mexico Natural Gas Pipelines mainly due to higher earnings in TGNH primarily related to the completion of the Southeast Gateway pipeline in second quarter 2025, partially offset by lower equity earnings from Sur de Texas as a result of peso-denominated financial exposure and higher income tax expense mainly related to foreign exchange impacts of U.S dollar-denominated liabilities
- increased EBITDA in Canadian Natural Gas Pipelines mainly due to higher flow-through depreciation and incentive earnings on the NGTL System and Mainline
- decreased Power and Energy Solutions EBITDA mainly attributable to lower net contributions from Bruce Power due to reduced generation primarily resulting from the Unit 4 MCR, partially offset by a higher contract price; and lower realized power prices in Canadian Power, partially offset by lower business development costs
- a negative foreign exchange impact of a weaker U.S. dollar on the Canadian dollar equivalent comparable EBITDA in our U.S. dollar-denominated operations, which was translated at a rate of 1.39 in 2025 versus 1.40 in 2024. Refer to the Foreign exchange section for additional information.

Due to the flow-through treatment of certain costs including depreciation, financial charges and income taxes in our Canadian rate-regulated pipelines, changes in these costs impact our comparable EBITDA despite having no significant effect on net income.

Comparable earnings from continuing operations

Fourth quarter 2025 versus fourth quarter 2024

Comparable earnings decreased by $76 million or $0.07 per common share for the three months ended December 31, 2025 compared to the same period in 2024 primarily due to the net effect of the following:

- changes in comparable EBITDA described above
- lower AFUDC primarily due to the completion of the Southeast Gateway pipeline
- higher income tax expense primarily due to the impact of Mexico foreign exchange exposure and higher flow-through income taxes
- higher depreciation and amortization primarily due to higher depreciation rates on the NGTL System under the 2025-2029 NGTL Settlement and from Columbia Gas as a result of the Columbia Gas Settlement
- lower interest income and other due to an increase in insurance-related provisions and lower interest earned on short-term investments
- higher interest expense due to lower realized gains on derivatives used to manage our interest rate risk, increased levels of short-term borrowing and long-term debt issuances and maturities
- higher net income attributable to non-controlling interests is primarily the result of higher net income recognized from the Columbia Gas and Columbia Gulf assets, partially offset by the net effect of higher tax expense, higher EBITDA and lower AFUDC in TGNH following Southeast Gateway pipeline's completion in second quarter 2025 and the overall impact of foreign exchange
- risk management activities used to manage our foreign exchange exposure to net liabilities in Mexico and to U.S. dollar-denominated income and the revaluation of our peso-denominated net monetary liabilities to U.S. dollars.

Foreign exchange

Certain of our businesses generate all or most of their earnings in U.S. dollars and, since we report our financial results in Canadian dollars, changes in the value of the U.S. dollar against the Canadian dollar directly affect our comparable EBITDA and may also impact comparable earnings. As our U.S. dollar-denominated operations continue to grow, this exposure increases. A portion of the U.S. dollar-denominated comparable EBITDA exposure is naturally offset by U.S. dollar-denominated amounts below comparable EBITDA within Depreciation and amortization, Interest expense and other income statement line items. A portion of the remaining exposure is actively managed on a rolling forward basis up to three years using foreign exchange derivatives; however, the natural exposure beyond that period remains. The net impact of the U.S. dollar movements on comparable earnings during the three months ended December 31, 2025 after considering natural offsets and economic hedges was not significant.

The components of our financial results denominated in U.S. dollars are set out in the table below, including our U.S. Natural Gas Pipelines and Mexico Natural Gas Pipelines operations. Comparable EBITDA is a non-GAAP measure.

Pre-tax U.S. dollar-denominated income and expense items - from continuing operations

three months ended December 31 (millions of US$)	**2025**	**2024**
Comparable EBITDA		
U.S. Natural Gas Pipelines	**996**	859
Mexico Natural Gas Pipelines	**285**	167
	1,281	1,026
Depreciation and amortization	**(211)**	(191)
Interest expense on long-term debt and junior subordinated notes	**(434)**	(440)
Interest income and other	**22**	51
Allowance for funds used during construction	**16**	159
Net (income) loss attributable to non-controlling interests included in comparable earnings and other	**(127)**	(125)
	547	480
Average exchange rate - U.S. to Canadian dollars	**1.39**	1.40

Foreign exchange related to Mexico Natural Gas Pipelines

Changes in the value of the Mexican peso against the U.S. dollar can affect our comparable earnings as a portion of our Mexico Natural Gas Pipelines monetary assets and liabilities are peso-denominated, while our financial results are denominated in U.S. dollars for our Mexico operations. These peso-denominated balances are revalued to U.S. dollars, creating foreign exchange gains and losses that are included in Income (loss) from equity investments, Foreign exchange (gains) losses, net and Net income (loss) attributable to non-controlling interests in the Consolidated statement of income.

In addition, foreign exchange gains or losses calculated for Mexico income tax purposes on the revaluation of U.S. dollar-denominated monetary assets and liabilities result in a peso-denominated income tax exposure for these entities, leading to fluctuations in Income from equity investments and Income tax expense. This exposure increases as our U.S. dollar-denominated net monetary liabilities grow.

The above exposures are managed using foreign exchange derivatives, although some unhedged exposure remains. The impacts of the foreign exchange derivatives are recorded in Foreign exchange (gains) losses, net in the Consolidated statement of income. Refer to the Financial risks and financial instruments section for additional information.

The period end exchange rates for one U.S. dollar to Mexican pesos were as follows:

December 31, 2025	**18.00**
December 31, 2024	20.87
December 31, 2023	16.91

A summary of the impacts of transactional foreign exchange gains and losses from changes in the value of the Mexican peso against the U.S. dollar and associated derivatives is set out in the table below:

three months ended December 31 (millions of $)	**2025**	**2024**
Comparable EBITDA - Mexico Natural Gas Pipelines[1]	**(12)**	30
Foreign exchange gains (losses), net included in comparable earnings	**36**	(21)
Income tax (expense) recovery included in comparable earnings	**(13)**	27
Net (income) loss attributable to non-controlling interests included in comparable earnings[2]	**—**	(3)
	11	33

1 Includes the foreign exchange impacts from the Sur de Texas joint venture recorded in Income (loss) from equity investments in the Consolidated statement of income.

2 Represents the non-controlling interest portion related to TGNH. Refer to the Corporate section for additional information.

Highlights by business segment

Canadian Natural Gas Pipelines

Canadian Natural Gas Pipelines segmented earnings increased by $58 million for the three months ended December 31, 2025 compared to the same period in 2024.

Net income for the NGTL System increased by $17 million for the three months ended December 31, 2025 compared to the same period in 2024 primarily due to higher incentive earnings. The NGTL System is currently operating under the 2025-2029 NGTL Settlement, which commenced on January 1, 2025 and includes an approved ROE of 10.1 per cent on 40 per cent deemed common equity. This settlement provides the NGTL System with higher depreciation rates and the opportunity to further increase depreciation rates with an incentive if tolls fall below specified levels, or if growth projects are undertaken. It also includes incentive mechanisms to reduce both physical emissions and emission compliance costs, while also providing incentive for certain operating costs where variances from projected amounts and emissions savings are shared with customers.

Net income for the Canadian Mainline increased by $5 million for the three months ended December 31, 2025 compared to the same period in 2024 mainly due to higher incentive earnings. The Canadian Mainline is operating under the 2021-2026 Mainline Settlement which includes an approved ROE of 10.1 per cent on 40 per cent deemed common equity and an incentive to decrease costs and increase revenues on the pipeline under a beneficial sharing mechanism with our customers.

Comparable EBITDA for Canadian Natural Gas Pipelines increased by $110 million for the three months ended December 31, 2025 compared to the same period in 2024 due to:

- higher flow-through depreciation and income taxes as well as higher incentive earnings on the NGTL System and the Canadian Mainline.

Depreciation and amortization increased by $52 million for the three months ended December 31, 2025 compared to the same period in 2024 primarily reflecting higher depreciation rates on the NGTL System under the 2025-2029 NGTL Settlement and an increase in assets placed in service on the Canadian Mainline.

U.S. Natural Gas Pipelines

U.S. Natural Gas Pipelines segmented earnings increased by $192 million for the three months ended December 31, 2025 compared to the same period in 2024 and included unrealized gains and losses from changes in the fair value of derivatives used in our U.S. natural gas marketing business which has been excluded from our calculation of comparable EBITDA and comparable EBIT.

A weaker U.S. dollar for the three months ended December 31, 2025 had a negative impact on the Canadian dollar equivalent segmented earnings from our U.S. dollar-denominated operations compared to the same period in 2024. Refer to the Foreign exchange section for additional information.

Comparable EBITDA for U.S. Natural Gas Pipelines increased by US$137 million for the three months ended December 31, 2025 compared to the same period in 2024 and was primarily due to the net effect of:

- a net increase in earnings from Columbia Gas as a result of higher transportation rates effective April 1, 2025, pursuant to the Columbia Gas Settlement. Refer to the U.S. Natural Gas Pipelines - Significant events section for additional information
- incremental earnings from projects placed in service, as well as increased earnings from additional contract sales on GTN
- higher realized earnings related to our U.S. natural gas marketing business primarily due to higher margins
- decreased earnings due to higher operational costs, reflective of increased system utilization across our footprint.

Depreciation and amortization increased by US$19 million for the three months ended December 31, 2025 compared to the same period in 2024 primarily due to new projects placed in service and depreciation rate changes as a result of the Columbia Gas Settlement.

Mexico Natural Gas Pipelines

Mexico Natural Gas Pipelines segmented earnings increased by $163 million for the three months ended December 31, 2025 compared to the same period in 2024 and included a recovery of $4 million (2024 – recovery of $3 million), on the expected credit loss provision related to the TGNH net investment in leases and certain contract assets in Mexico, which has been excluded from our calculation of comparable EBITDA and comparable EBIT.

A weaker U.S. dollar for the three months and year ended December 31, 2025 had a negative impact on the Canadian dollar equivalent segmented earnings from our U.S. dollar-denominated operations in Mexico compared to the same period in 2024. Refer to the Foreign exchange section for additional information.

Comparable EBITDA for Mexico Natural Gas Pipelines increased by US$118 million for the three months ended December 31, 2025 compared with the same period in 2024, due to the net effect of:

- higher earnings in TGNH due to the completion of the Southeast Gateway pipeline in second quarter 2025
- lower equity earnings from Sur de Texas primarily due to the foreign exchange impacts on the revaluation of peso-denominated liabilities as a result of a stronger Mexican peso and higher income tax expense mainly related to foreign exchange impacts of U.S. dollar-denominated liabilities. Refer to the Sur de Texas results section for additional information.

Depreciation and amortization was generally consistent for the three months ended December 31, 2025 compared to the same period in 2024. Under sales-type lease accounting, our in-service TGNH pipeline assets are derecognized from Plant, property and equipment and recorded as a net investment in lease on our Condensed consolidated balance sheet with no depreciation expense being recognized.

Power and Energy Solutions

Power and Energy Solutions segmented earnings decreased by $140 million for the three months ended December 31, 2025 compared to the same period in 2024 and included the following specific items which have been excluded from our calculation of comparable EBITDA and comparable EBIT:

- a pre-tax impairment charge in 2025 of $110 million (2024 - $36 million) for certain Power and Energy Solutions projects following our decision to discontinue development along with updated forecast assumptions as we refocus our Power and Energy Solutions strategy
- our proportionate share of Bruce Power's unrealized gains and losses on funds invested for post-retirement benefits and risk management activities
- unrealized gains and losses from changes in the fair value of derivatives used to reduce commodity exposures.

Comparable EBITDA for Power and Energy Solutions decreased by $124 million for the three months ended December 31, 2025 compared to the same period in 2024 primarily due to the net effect of:

- lower Bruce Power contributions from reduced generation due to the Unit 4 MCR, planned Unit 2 outage in fourth quarter 2025 and increased operating costs, partially offset by a higher contract price. Refer to the Bruce Power results section for additional information
- decreased Canadian Power financial results primarily from lower realized power prices
- increased Natural Gas Storage and other is primarily due to lower business development costs.

Depreciation and amortization generally consistent for the three months ended December 31, 2025 compared to the same period in 2024.

Corporate

Corporate segmented earnings increased by $17 million for the three months ended December 31, 2025 compared to the same period in 2024. Corporate segmented losses included a pre-tax charge of $9 million for the three months ended December 31, 2024 related to Focus Project costs, which has been excluded from our calculation of comparable EBITDA and comparable EBIT.

Comparable EBITDA and EBIT for Corporate increased by $8 million for the three months ended December 31, 2025 compared to the same period in 2024.

QUARTERLY RESULTS - FROM DISCONTINUED OPERATIONS

Factors affecting financial information by quarter

The quarterly results section references non-GAAP measures, which are described on page 22. These measures do not have any standardized meaning as prescribed by GAAP and therefore may not be comparable to similar measures presented by other entities.

In fourth quarter 2025, comparable earnings from discontinued operations also excluded:

- a pre-tax recovery of $8 million primarily resulting from the resolution reached in September 2025 under the Separation Agreement with South Bow.

In third quarter 2025, comparable earnings from discontinued operations also excluded:

- a pre-tax charge of $196 million primarily resulting from the resolution reached in September 2025 under the Separation Agreement with South Bow.

In second quarter 2025, comparable earnings from discontinued operations also excluded:

- a pre-tax impairment charge of $29 million related to our estimate of Keystone XL contractual recoveries.

In fourth quarter 2024, comparable earnings from discontinued operations also excluded:

- a pre-tax charge of $85 million from Liquids Pipelines business separation costs related to the Spinoff Transaction, of which $75 million was recognized in segmented earnings and $10 million in interest income
- a pre-tax expense of $37 million related to our estimate of potential incremental costs resulting from the Milepost 14 incident. This amount represents our 86 per cent share pursuant to the indemnity provisions in the Separation Agreement
- a pre-tax recovery of $3 million as a result of the FERC Administrative Law Judge decision on Keystone in respect of a tolling-related complaint pertaining to amounts recognized in prior periods.

In third quarter 2024, comparable earnings from discontinued operations also excluded:

- a pre-tax charge of $67 million due to Liquids Pipelines business separation costs related to the Spinoff Transaction
- a pre-tax expense of $21 million related to Keystone XL asset disposition and termination activities
- a pre-tax charge of $15 million related to the FERC Administrative Law Judge decision on Keystone in respect of a tolling-related complaint pertaining to amounts recognized in prior periods.

In second quarter 2024, comparable earnings from discontinued operations also excluded:

- a pre-tax charge of $29 million due to Liquids Pipelines business separation costs related to the Spinoff Transaction.

In first quarter 2024, comparable earnings from discontinued operations also excluded:

- a pre-tax charge of $16 million due to Liquids Pipelines business separation costs related to the Spinoff Transaction.

Results from discontinued operations

three months ended December 31 (millions of $, except per share amounts)	**2025**	**2024**
Segmented earnings (losses) from discontinued operations	**(6)**	(109)
Interest income and other	**14**	(10)
Income (loss) from discontinued operations before income taxes	**8**	(119)
Income tax (expense) recovery	**13**	21
Net income (loss) from discontinued operations, net of tax	**21**	(98)
Net income (loss) per common share from discontinued operations - basic	**$0.02**	($0.09)

Net income from discontinued operations, net of tax in the three months ended in December 31, 2025 was $21 million or $0.02 per common share (2024 - net loss of $98 million or loss of $0.09 per common share), an increase of $119 million or $0.11 per common share.

Reconciliation of net income (loss) from discontinued operations, net of tax to comparable earnings from discontinued operations

three months ended December 31 (millions of $, except per share amounts)	**2025**	**2024**
Net income (loss) from discontinued operations, net of tax	**21**	(98)
Specific items (pre tax):		
South Bow settlement[1]	**(8)**	—
Liquids Pipelines business separation costs	**—**	85
Milepost 14 incremental costs	**—**	37
Keystone regulatory decisions	**—**	(3)
Taxes on specific items	**(13)**	(21)
Comparable earnings from discontinued operations	**—**	—
Net income (loss) per common share from discontinued operations	**$0.02**	($0.09)
Specific items (net of tax)	**(0.02)**	0.09
Comparable earnings per common share from discontinued operations	**—**	—

1 A pre-tax recovery of $8 million for the three months ended December 31, 2025 resulting from the resolution reached in September 2025 under the Separation Agreement with South Bow.

Glossary

Units of measure

Bcf	Billion cubic feet
Bcf/d	Billion cubic feet per day
GWh	Gigawatt hours
km	Kilometres
MMcf/d	Million cubic feet per day
MW	Megawatt(s)
MWh	Megawatt hours
TJ/d	Terajoule per day

General terms and terms related to our operations

CEO	Chief Executive Officer
CFO	Chief Financial Officer
cogeneration facilities	Facilities that produce both electricity and useful heat at the same time
DRP	Dividend Reinvestment and Share Purchase Plan
Empress	A major delivery/receipt point for natural gas near the Alberta/Saskatchewan border
ESG	Environmental, social and governance
FID	Final investment decision
force majeure	Unforeseeable circumstances that prevent a party to a contract from fulfilling it
GHG	Greenhouse gas
HCAs	High-consequence areas
HSSE	Health, safety, sustainability and environment
investment base	Includes rate base, as well as assets under construction
LDC	Local distribution company
LNG	Liquefied natural gas
OM&A	Operating, maintenance and administration
PPA	Power purchase arrangement
rate base	Average assets in service, working capital and deferred amounts used in setting of regulated rates
RNG	Renewable natural gas
TSA	Transportation Service Agreement
TOMS	TC Energy's Operational Management System
WCSB	Western Canadian Sedimentary basin

Accounting terms

AFUDC	Allowance for funds used during construction
U.S. GAAP / GAAP	U.S. generally accepted accounting principles
RRA	Rate-regulated accounting
ROE	Return on common equity

Government and regulatory bodies terms

AER	Alberta Energy Regulator
CER	Canada Energy Regulator
CFE	Comisión Federal de Electricidad (Mexico)
CNE	Comisión Nacional de Energía (Mexico)
CRE	Comisión Reguladora de Energía, or Energy Regulatory Commission (Mexico)
ECCC	Environment and Climate Change Canada
FERC	Federal Energy Regulatory Commission (U.S.)
IESO	Independent Electricity System Operator (Ontario)
IFRS S2	International Financial Reporting Standards S2 Climate-related Disclosures
NYSE	New York Stock Exchange
OBPS	Output Based Pricing System
OPG	Ontario Power Generation
PHMSA	Pipeline and Hazardous Materials Safety Administration
SEC	U.S. Securities and Exchange Commission
SENER	Secretaría de Energía or Mexican Ministry of Energy
TCFD	Task Force on Climate-Related Financial Disclosures
TNFD	Task Force on Nature-related Financial Disclosures
TSX	Toronto Stock Exchange

Management's Report on Internal Control over Financial Reporting

The consolidated financial statements and Management's Discussion and Analysis (MD&A) included in this Annual Report are the responsibility of the management of TC Energy Corporation (TC Energy or the Company) and have been approved by the Board of Directors of the Company. The consolidated financial statements have been prepared by management in accordance with United States generally accepted accounting principles (GAAP) and include amounts that are based on estimates and judgments. The MD&A is based on the Company's financial results. It compares the Company's financial and operating performance in 2025 to that in 2024, and highlights significant changes between 2024 and 2023. The MD&A should be read in conjunction with the consolidated financial statements and accompanying notes. Financial information contained elsewhere in this Annual Report is consistent with the consolidated financial statements.

Management is responsible for establishing and maintaining adequate internal control over financial reporting for the Company. Management has designed and maintains a system of internal control over financial reporting, including a program of internal audits to carry out its responsibility. Management believes these controls provide reasonable assurance that financial records are reliable and form a proper basis for the preparation of financial statements. The internal control over financial reporting includes management's communication to employees of policies that govern ethical business conduct.

Under the supervision and with the participation of the President and Chief Executive Officer and the Chief Financial Officer, management conducted an evaluation of the effectiveness of its internal control over financial reporting based on the framework in Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Management concluded, based on its evaluation, that internal control over financial reporting was effective as of December 31, 2025, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external reporting purposes.

The Board of Directors is responsible for reviewing and approving the consolidated financial statements and MD&A and ensuring that management fulfills its responsibilities for financial reporting and internal control. The Board of Directors carries out these responsibilities primarily through the Audit Committee, which consists of independent, non-management directors. The Audit Committee meets with management at least four times a year and meets independently with internal and external auditors and as a group to review any significant accounting, internal control and auditing matters in accordance with the terms of the Charter of the Audit Committee, which is set out in the Annual Information Form. The Audit Committee's responsibilities include overseeing management's performance in carrying out its financial reporting responsibilities and reviewing the Annual Report, including the consolidated financial statements and MD&A, before these documents are submitted to the Board of Directors for approval. The internal and independent external auditors have access to the Audit Committee without the requirement to obtain prior management approval.

The Audit Committee approves the terms of engagement of the independent external auditors and reviews the annual audit plan, the Auditors' Report and the results of the audit. It also recommends to the Board of Directors the firm of external auditors to be appointed by the shareholders.

The shareholders have appointed KPMG LLP as independent external auditors to express an opinion as to whether the consolidated financial statements present fairly, in all material respects, the Company's consolidated financial position, results of operations and cash flows in accordance with GAAP. The reports of KPMG LLP outline the scope of its examinations and its opinions on the consolidated financial statements and the effectiveness of the Company's internal control over financial reporting.

François L. Poirier
President and
Chief Executive Officer

Sean O'Donnell
Executive Vice-President and
Chief Financial Officer

February 12, 2026

Report of Independent Registered Public Accounting Firm

To the Shareholders and Board of Directors
TC Energy Corporation:

Opinion on the Consolidated Financial Statements

We have audited the accompanying consolidated balance sheets of TC Energy Corporation (the Company) as of December 31, 2025 and 2024, the related consolidated statements of income, comprehensive income, equity, and cash flows for each of the years in the three-year period ended December 31, 2025, and the related notes (collectively, the consolidated financial statements). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2025 and 2024, and the results of operations and its cash flows for each of the years in the three-year period ended December 31, 2025, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the Company's internal control over financial reporting as of December 31, 2025, based on criteria established in Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission, and our report dated February 12, 2026 expressed an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

Basis for Opinion

These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We are a public accounting firm registered with the 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 audit to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud. Our audits 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. We believe that our audits provide a reasonable basis for our opinion.

Critical Audit Matters

The critical audit matters communicated below are matters arising from the current period audit of the consolidated financial statements that were communicated or required to be communicated to the audit committee and that: (1) relate to accounts or disclosures that are material to the consolidated financial statements and (2) 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 matters below, providing separate opinions on the critical audit matters or on the accounts or disclosures to which they relate.

Determination of fair value of the Southeast Gateway pipeline

As discussed in Notes 2 and 9 to the consolidated financial statements, the Company recognized a sales-type lease for the Southeast Gateway pipeline and recorded net investment in lease of $6.6 billion and selling profit or loss of nil upon derecognition of the carrying value of the underlying assets. At lease commencement, the Company recognizes a net investment in lease equal to the present value of the future lease payments and the estimated residual value of the underlying assets discounted at the rate implicit in the lease. The carrying value of the underlying assets is derecognized, with related gains/losses, if any, recognized in the Consolidated statement of income.

We identified the determination of fair value of the Southeast Gateway pipeline as a critical audit matter. The extent of management judgment with regards to certain qualitative factors that support the conclusion that the fair value of the Southeast Gateway pipeline approximated the carrying value of its underlying assets required subjective auditor judgment. In addition, the audit effort associated with this evaluation required specialized skills and knowledge.

The following are the primary procedures we performed to address this critical audit matter. We evaluated the design and tested the operating effectiveness of certain internal controls related to this critical audit matter. This included controls related to the Company's determination that the fair value of the Southeast Gateway pipeline approximated the carrying value of its underlying assets. We evaluated the Company's qualitative assessment of factors that supported the Company's judgment that the fair value of the underlying assets approximated their carrying value. We evaluated the Company's forecasted cash flows derived from a market participant's expected use of the underlying assets to determine an implied rate of return, which was compared to estimated rates of return a market participant would require. In addition, we involved valuation professionals with specialized skills and knowledge, who assisted in:

- evaluating the implied return of the underlying assets by independently developing an expectation for the rate of return a market participant would expect by using publicly available market data for comparable entities; and
- evaluating the implied return of the underlying assets by comparing the implied EBITDA multiple to EBITDA multiples using publicly available market data for comparable entities.

Valuation of goodwill for the Columbia reporting unit

As discussed in Notes 2 and 13 to the consolidated financial statements, the goodwill balance as of December 31, 2025 for the Columbia reporting unit was $10,082 million. The Company performs an annual review for goodwill impairment at the reporting unit level which is one level below the Company's operating segments. The Company can elect to proceed directly to the quantitative goodwill impairment test for any of its reporting units. If the quantitative goodwill impairment test is performed, the Company compares the fair value of the reporting unit to its carrying value, including goodwill. If the carrying value of a reporting unit exceeds its fair value, goodwill impairment is measured at the amount by which the reporting unit's carrying value exceeds its fair value. The fair value of the reporting unit was determined by using a discounted cash flow model which requires the use of assumptions related to revenue and capital expenditure projections (collectively, the "key assumptions"). The Company elected to proceed directly to the quantitative goodwill impairment test as of December 31, 2025 for the Columbia reporting unit and determined that the fair value of the Columbia reporting unit, exceeded its carrying value, including goodwill, as of December 31, 2025. We identified the evaluation of the key assumptions used in the valuation of goodwill for the Columbia reporting unit as a critical audit matter. A high degree of auditor judgment was required to evaluate the key assumptions. Minor changes to the key assumptions could have had a significant effect on the Company's determination of the fair value of the Columbia reporting unit.

The following are the primary procedures we performed to address this critical audit matter. We evaluated the design and tested the operating effectiveness of certain internal controls related to the Company's determination of the fair value of the Columbia reporting unit and its evaluation of the key assumptions. We compared the Company's key assumptions used in the prior quantitative goodwill impairment test to actual results to assess the Company's ability to accurately forecast. We evaluated the Company's key assumptions in the December 31, 2025 impairment test by comparing them to actual historical results, the outcome of the Columbia Gas Settlement and to assumptions used in industry publications related to North American and global energy consumption and production forecasts.

/s/ KPMG LLP

Chartered Professional Accountants
We have served as the Company's auditor since 1956.

Calgary, Canada
February 12, 2026

Report of Independent Registered Public Accounting Firm

To the Shareholders and Board of Directors
TC Energy Corporation:

Opinion on Internal Control Over Financial Reporting

We have audited TC Energy Corporation's (the Company) internal control over financial reporting as of December 31, 2025, based on criteria established in Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2025, based on criteria established in Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated balance sheets of the Company as of December 31, 2025 and 2024, the related consolidated statements of income, comprehensive income, equity, and cash flows for each of the years in the three-year period ended December 31, 2025, and the related notes (collectively, the consolidated financial statements), and our report dated February 12, 2026 expressed an unqualified opinion on those consolidated financial statements.

Basis for Opinion

The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control over Financial Reporting included in the Company's Consolidated Financial Statements. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit. We are a public accounting firm registered with the 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 audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. 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 audit also included performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

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 (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) 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 (3) 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.

/s/ KPMG LLP

Chartered Professional Accountants
Calgary, Canada
February 12, 2026

Consolidated statement of income

year ended December 31 (millions of Canadian $, except per share amounts)	2025	2024	2023
Revenues (Note 6)			
Canadian Natural Gas Pipelines	**5,785**	5,600	5,173
U.S. Natural Gas Pipelines	**7,145**	6,339	6,229
Mexico Natural Gas Pipelines	**1,450**	870	846
Power and Energy Solutions	**845**	954	1,019
Corporate	**14**	8	—
	15,239	13,771	13,267
Income (Loss) from Equity Investments (Note 10)	**1,274**	1,558	1,310
Impairment of Equity Investment (Note 10)	**—**	—	(2,100)
Operating and Other Expenses			
Plant operating costs and other	**4,619**	4,413	4,073
Commodity purchases resold	**208**	217	80
Property taxes	**881**	820	781
Depreciation and amortization	**2,769**	2,535	2,446
	8,477	7,985	7,380
Net Gain (Loss) on Sale of Assets (Note 29)	**—**	620	—
Financial Charges			
Interest expense (Note 19)	**3,407**	3,019	2,966
Allowance for funds used during construction	**(453)**	(784)	(575)
Foreign exchange (gains) losses, net (Note 21)	**(157)**	147	(320)
Interest income and other	**(205)**	(324)	(272)
	2,592	2,058	1,799
Income (Loss) from Continuing Operations before Income Taxes	**5,444**	5,906	3,298
Income Tax Expense (Recovery) from Continuing Operations (Note 18)			
Current	**367**	495	864
Deferred	**771**	427	(22)
	1,138	922	842
Net Income (Loss) from Continuing Operations	**4,306**	4,984	2,456
Net Income (Loss) from Discontinued Operations, Net of Tax (Note 4)	**(212)**	395	612
Net Income (Loss)	**4,094**	5,379	3,068
Net income (loss) attributable to non-controlling interests (Note 22)	**575**	681	146
Net Income (Loss) Attributable to Controlling Interests	**3,519**	4,698	2,922
Preferred share dividends	**119**	104	93
Net Income (Loss) Attributable to Common Shares	**3,400**	4,594	2,829
Amounts Attributable to Common Shares			
Net income (loss) from continuing operations	**4,306**	4,984	2,456
Net income (loss) attributable to non-controlling interests (Note 22)	**575**	681	146
Net income (loss) attributable to controlling interests from continuing operations	**3,731**	4,303	2,310
Preferred share dividends	**119**	104	93
Net income (loss) attributable to common shares from continuing operations	**3,612**	4,199	2,217
Net income (loss) from discontinued operations, net of tax (Note 4)	**(212)**	395	612
Net Income (Loss) Attributable to Common Shares	**3,400**	4,594	2,829
Net Income (Loss) per Common Share - Basic and Diluted (Note 23)			
Continuing operations	**$3.47**	$4.05	$2.15
Discontinued operations	**($0.20)**	$0.38	$0.60
	$3.27	$4.43	$2.75
Dividends Declared per Common Share	**$3.40**	$3.7025	$3.72
Weighted Average Number of Common Shares (millions) (Note 23)			
Basic	**1,040**	1,038	1,030
Diluted	**1,040**	1,038	1,030

The accompanying Notes to the consolidated financial statements are an integral part of these statements.

Consolidated statement of comprehensive income

year ended December 31 (millions of Canadian $)	2025	2024	2023
Net Income (Loss)	**4,094**	5,379	3,068
Other Comprehensive Income (Loss), Net of Tax			
Foreign currency translation gains and losses on net investment in foreign operations	**(978)**	1,602	(1,141)
Reclassification of foreign currency translation (gains) losses on net investment on disposal of foreign operations	**—**	(25)	—
Change in fair value of net investment hedges	**1**	(18)	17
Change in fair value of cash flow hedges	**(22)**	35	—
Reclassification to net income of (gains) losses on cash flow hedges	**31**	(16)	74
Unrealized actuarial gains (losses) on pension and other post-retirement benefit plans	**79**	83	(11)
Reclassification to net income of actuarial (gains) losses on pension and other post-retirement benefit plans	**—**	(6)	—
Other comprehensive income (loss) on equity investments	**2**	173	(211)
Other comprehensive income (loss) (Note 25)	**(887)**	1,828	(1,272)
Comprehensive Income (Loss)	**3,207**	7,207	1,796
Comprehensive income (loss) attributable to non-controlling interests	**64**	1,584	(220)
Comprehensive Income (Loss) Attributable to Controlling Interests	**3,143**	5,623	2,016
Preferred share dividends	**119**	104	93
Comprehensive Income (Loss) Attributable to Common Shares	**3,024**	5,519	1,923

The accompanying Notes to the consolidated financial statements are an integral part of these statements.

Consolidated statement of cash flows

year ended December 31 (millions of Canadian $)	2025	2024	2023
Cash Generated from Operations			
Net income (loss)	**4,094**	5,379	3,068
Depreciation and amortization	**2,769**	2,788	2,778
Deferred income taxes (Note 18)	**766**	493	11
(Income) loss from equity investments (Notes 5 and 10)	**(1,274)**	(1,608)	(1,377)
Impairment of equity investment (Note 10)	**—**	—	2,100
Distributions received from operating activities of equity investments (Note 10)	**1,616**	1,675	1,254
Employee post-retirement benefits funding, net of expense (Note 26)	**3**	11	(17)
Equity allowance for funds used during construction	**(320)**	(512)	(367)
Unrealized (gains) losses on financial instruments (Note 27)	**(235)**	340	(342)
Expected credit loss provision (Note 27)	**83**	(22)	(83)
Foreign exchange (gains) losses, net – intercompany loan	**149**	(216)	44
Net (gain) loss on sale of assets (Note 29)	**—**	(620)	—
Asset impairment charge and other (Note 4)	**29**	21	(4)
Other	**169**	(232)	(4)
(Increase) decrease in operating working capital (Note 28)	**(503)**	199	207
Net cash provided by operations	**7,346**	7,696	7,268
Investing Activities			
Capital expenditures (Note 5)	**(5,270)**	(6,308)	(8,007)
Capital projects in development (Note 5)	**(16)**	(50)	(142)
Contributions to equity investments (Notes 5 and 10)	**(1,051)**	(4,683)	(4,149)
Other distributions from equity investments (Note 10)	**5**	3,686	23
Proceeds from sales of assets, net of transaction costs (Note 29)	**—**	791	33
Acquisitions, net of cash acquired (Note 29)	**—**	—	(307)
Loans to affiliate (issued) repaid, net	**—**	—	250
Deferred amounts and other	**(126)**	(345)	12
Net cash (used in) provided by investing activities	**(6,458)**	(6,909)	(12,287)
Financing Activities			
Notes payable issued (repaid), net	**876**	341	(6,299)
Long-term debt issued, net of issue costs	**5,413**	8,089	15,884
Long-term debt repaid (Notes 19 and 20)	**(6,116)**	(9,273)	(3,772)
Junior subordinated notes issued, net of issue costs	**2,545**	1,465	—
Dividends on common shares	**(3,507)**	(3,953)	(2,787)
Dividends on preferred shares	**(114)**	(99)	(92)
Common shares issued, net of issue costs	**104**	88	4
Preferred shares redeemed (Note 24)	**(250)**	—	—
Distributions to non-controlling interests and other	**(929)**	(755)	(173)
Contributions from non-controlling interests	**—**	21	—
Cash received from factoring arrangement (Note 9)	**351**	—	—
Loan from affiliate (Note 11)	**111**	—	—
Disposition of equity interest, net of transaction costs (Note 29)	**—**	419	5,328
Cash transferred to South Bow, net of debt settlements	**—**	(244)	—
Gains (losses) on settlement of financial instruments	**—**	27	—
Net cash (used in) provided by financing activities	**(1,516)**	(3,874)	8,093
Effect of Foreign Exchange Rate Changes on Cash and Cash Equivalents	**(5)**	210	(16)
Increase (Decrease) in Cash and Cash Equivalents	**(633)**	(2,877)	3,058
Cash and Cash Equivalents - Beginning of year	**801**	3,678	620
Cash and Cash Equivalents - End of year	**168**	801	3,678

Includes continuing and discontinued operations. Refer to Note 4, Discontinued operations, for additional information related to cash flows from discontinued operations.

The accompanying Notes to the consolidated financial statements are an integral part of these statements.

Consolidated balance sheet

at December 31 (millions of Canadian $)		2025	2024
ASSETS			
Current Assets			
Cash and cash equivalents		**168**	801
Accounts receivable		**2,794**	2,611
Inventories		**782**	747
Other current assets (Note 7)		**2,375**	1,339
Current assets of discontinued operations (Note 4)		**197**	235
		6,316	5,733
Plant, Property and Equipment (Note 8)		**71,054**	77,501
Net Investment in Leases (Note 9)		**8,110**	2,477
Equity Investments (Note 10)		**11,358**	10,636
Restricted Investments		**3,502**	2,998
Regulatory Assets (Note 12)		**2,913**	2,682
Goodwill (Note 13)		**13,016**	13,670
Other Long-Term Assets (Note 14)		**2,482**	2,410
Long-Term Assets of Discontinued Operations (Note 4)		**—**	136
		118,751	118,243
LIABILITIES			
Current Liabilities			
Notes payable (Note 15)		**1,200**	387
Accounts payable and other (Note 16)		**5,274**	5,297
Dividends payable		**901**	874
Accrued interest		**858**	828
Current portion of long-term debt (Note 19)		**1,545**	2,955
Current liabilities of discontinued operations (Note 4)		**181**	170
		9,959	10,511
Regulatory Liabilities (Note 12)		**5,841**	5,303
Other Long-Term Liabilities (Note 17)		**1,034**	1,051
Deferred Income Tax Liabilities (Note 18)		**7,677**	6,884
Long-Term Debt (Note 19)		**45,247**	44,976
Junior Subordinated Notes (Note 20)		**12,094**	11,048
Long-Term Liabilities of Discontinued Operations (Note 4)		**—**	110
		81,852	79,883
EQUITY			
Common shares, no par value (Note 23)		**30,218**	30,101
Issued and outstanding:	December 31, 2025 – 1,041 million shares December 31, 2024 – 1,039 million shares		
Preferred shares (Note 24)		**2,255**	2,499
Retained earnings (Accumulated deficit)		**(5,925)**	(5,241)
Accumulated other comprehensive income (loss) (Note 25)		**747**	233
Controlling Interests		**27,295**	27,592
Non-Controlling Interests (Note 22)		**9,604**	10,768
		36,899	38,360
		118,751	118,243

Commitments, Contingencies and Guarantees (Note 30)
Variable Interest Entities (Note 31)

The accompanying Notes to the consolidated financial statements are an integral part of these statements.

On behalf of the Board:

François L. Poirier, Director

Una M. Power, Director

Consolidated statement of equity

year ended December 31 (millions of Canadian $)	**2025**	**2024**	**2023**
Common Shares (Note 23)			
Balance at beginning of year	**30,101**	30,002	28,995
Shares issued:			
Exercise of stock options	**117**	99	4
Dividend reinvestment and share purchase plan	**—**	—	1,003
Balance at end of year	**30,218**	30,101	30,002
Preferred Shares (Note 24)			
Balance at beginning of year	**2,499**	2,499	2,499
Redemption of shares	**(244)**	—	—
Balance at end of year	**2,255**	2,499	2,499
Additional Paid-In Capital			
Balance at beginning of year	**—**	—	722
Issuance of stock options, net of exercises	**(7)**	(5)	9
Disposition of equity interest, net of transaction costs (Note 29)	**—**	(41)	(3,537)
Reclassification of additional paid-in capital deficit to accumulated deficit	**7**	46	2,806
Balance at end of year	**—**	—	—
Retained Earnings (Accumulated Deficit)			
Balance at beginning of year	**(5,241)**	(2,997)	819
Net income (loss) attributable to controlling interests	**3,519**	4,698	2,922
Common share dividends	**(3,537)**	(3,842)	(3,839)
Preferred share dividends	**(117)**	(104)	(93)
Spinoff of Liquids Pipelines business (Note 4)	**(542)**	(2,950)	—
Reclassification of additional paid-in capital deficit to accumulated deficit	**(7)**	(46)	(2,806)
Balance at end of year	**(5,925)**	(5,241)	(2,997)
Accumulated Other Comprehensive Income (Loss) (Note 25)			
Balance at beginning of year	**233**	49	955
Other comprehensive income (loss) attributable to controlling interests	**(376)**	946	(379)
Impact of non-controlling interest (Note 29)	**348**	(21)	(527)
Spinoff of Liquids Pipelines business (Note 4)	**542**	(741)	—
Balance at end of year	**747**	233	49
Equity Attributable to Controlling Interests	**27,295**	27,592	29,553
Equity Attributable to Non-Controlling Interests			
Balance at beginning of year	**10,768**	9,455	126
Net income (loss) attributable to non-controlling interests (Note 22)	**575**	681	146
Other comprehensive income (loss) attributable to non-controlling interests	**(511)**	903	(366)
Disposition of equity and non-controlling interests (Note 29)	**(348)**	461	9,451
Non-controlling interests on acquisition of Texas Wind Farms (Note 29)	**—**	—	222
Contributions from non-controlling interests	**—**	21	—
Distributions declared to non-controlling interests	**(880)**	(753)	(124)
Balance at end of year	**9,604**	10,768	9,455
Total Equity	**36,899**	38,360	39,008

The accompanying Notes to the consolidated financial statements are an integral part of these statements.

Notes to consolidated financial statements

1. DESCRIPTION OF TC ENERGY'S BUSINESS

TC Energy Corporation (TC Energy or the Company) is a leading North American energy infrastructure company which operates in four business segments: Canadian Natural Gas Pipelines, U.S. Natural Gas Pipelines, Mexico Natural Gas Pipelines and Power and Energy Solutions. These segments offer different products and services, including certain natural gas and electricity marketing and storage services. The Company also has a Corporate segment, consisting of corporate and administrative functions that provide governance, financing and other support to the Company's business segments.

Canadian Natural Gas Pipelines

The Canadian Natural Gas Pipelines segment primarily consists of the Company's investments in 40,984 km (25,467 miles) of regulated natural gas pipelines currently in operation.

U.S. Natural Gas Pipelines

The U.S. Natural Gas Pipelines segment primarily consists of the Company's investments in 49,587 km (30,811 miles) of regulated natural gas pipelines, 532 Bcf of regulated natural gas storage facilities and other assets currently in operation.

Mexico Natural Gas Pipelines

The Mexico Natural Gas Pipelines segment primarily consists of the Company's investments in 3,600 km (2,235 miles) of regulated natural gas pipelines currently in operation.

Power and Energy Solutions

The Power and Energy Solutions segment primarily consists of the Company's investments in approximately 4,650 MW of power generation facilities and 118 Bcf of non-regulated natural gas storage facilities. These assets are located in Alberta, Ontario, Québec, New Brunswick and Texas. In addition, TC Energy has physical and virtual power purchase agreements (PPAs) in Canada and the U.S. to buy and/or sell power from wind and solar facilities. These PPAs have the potential to be leases, derivatives or revenue arrangements depending on the contractual terms of the agreement.

Spinoff of Liquids Pipelines Business

On October 1, 2024, TC Energy completed the spinoff of its Liquids Pipelines business into the new public company, South Bow Corporation (South Bow) (the Spinoff Transaction). Refer to Note 4, Discontinued operations, for additional information.

2. ACCOUNTING POLICIES

The Company's consolidated financial statements have been prepared by management in accordance with U.S. generally accepted accounting principles. Amounts are stated in Canadian dollars unless otherwise indicated.

Basis of Presentation

These consolidated financial statements include the accounts of TC Energy and its subsidiaries. The Company consolidates variable interest entities (VIEs) for which it is considered to be the primary beneficiary as well as voting interest entities in which it has a controlling financial interest. Interests in consolidated entities owned by other parties are presented as non-controlling interests. TC Energy uses the equity method of accounting for joint ventures in which the Company is able to exercise joint control and for investments in which the Company is able to exercise significant influence.

The Spinoff Transaction represented a strategic shift that had a major effect on the Company's operations and consolidated financial results. Accordingly, the historical results of the Liquids Pipelines business are presented as discontinued operations and have been excluded from continuing operations and segment disclosures for all periods presented. The Notes to the consolidated financial statements reflect continuing operations only, unless otherwise indicated. Prior to the spinoff, the operations of the Liquids Pipelines business were materially reported as the Company's Liquids Pipelines segment. Refer to Note 4, Discontinued operations, and Note 5, Segmented information, for additional information.

Certain prior year amounts have been reclassified to conform to current year presentation.

Out-of-Period Adjustments

During second quarter 2025, the Company recorded out-of-period adjustments to reclassify a pro rata portion of its net investment hedge losses recorded in Accumulated other comprehensive income (loss) (AOCI).

The adjustments included (i) a reclassification of net investment hedge losses of $348 million from AOCI to Non-controlling interests (NCI) related to the sale of 40 per cent of Columbia Gas and Columbia Gulf on October 4, 2023, which was presented as Impact of non-controlling interest and Disposition of equity interests, respectively, in the Consolidated statement of equity; and (ii) a reclassification of net investment hedge losses of $542 million related to the spinoff of the Company's Liquids Pipelines business that occurred on October 1, 2024 from AOCI to Retained earnings (Accumulated deficit).

The Company determined that the impact of these out-of-period adjustments was not material, individually or in the aggregate, to any previously reported quarterly or annual financial statements and is not material to the Company's consolidated financial statements.

Use of Estimates and Judgments

In preparing these consolidated financial statements, TC Energy is required to make estimates and assumptions that affect both the amount and timing of recording assets, liabilities, revenues and expenses since the determination of these items may be dependent on future events. The Company uses the most current information available and exercises careful judgment in making these estimates and assumptions.

Certain estimates and judgments have a material impact on the consolidated financial statements where the assumptions underlying these accounting estimates relate to matters that are highly uncertain at the time they are made or are subjective. These estimates and judgments include, but are not limited to:

- fair value of the Southeast Gateway pipeline used to record a net investment upon lease commencement (Note 9)
- fair value of reporting units that contain goodwill (Note 13).

Some of the estimates and judgments the Company has to make have a material impact on the consolidated financial statements, but do not involve significant subjectivity or uncertainty. These estimates and judgments include, but are not limited to:

- recoverability and depreciation rates of plant, property and equipment (Note 8)
- allocation of consideration to lease and non-lease components in a contract that contains a lease (Note 9)
- assumptions used to measure the carrying amount of and expected credit losses on net investment in leases and certain contract assets (Notes 9 and 27)
- fair value of equity investments (Note 10)
- carrying value of regulatory assets and liabilities (Note 12)
- recognition of asset retirement obligations (Note 17)
- provisions for income taxes, including valuation allowances and releases as well as tax positions that may be reviewed as part of an audit by tax authorities (Note 18)
- assumptions used to measure retirement and other post-retirement benefit obligations (Note 26)
- fair value of financial instruments (Notes 26 and 27)
- commitments and provisions for contingencies and guarantees (Note 30).

TC Energy continues to assess climate-related impacts on the consolidated financial statements. There are ongoing developments in the sustainability frameworks and regulatory initiatives that could further impact accounting estimates and judgments including, but not limited to, assessment of asset useful lives, goodwill valuation, impairment of plant, property and equipment, accrued environmental costs and asset retirement obligations. The impact of these changes is continuously assessed to ensure any changes in assumptions that would impact estimates listed above are adjusted on a timely basis.

Actual results could differ from these estimates.

Regulation

Certain Canadian, U.S. and Mexico natural gas pipeline and storage assets are regulated with respect to construction, operations and the determination of tolls. In Canada, regulated natural gas pipelines are subject to the authority of the Canada Energy Regulator (CER), the Alberta Energy Regulator or the BC Energy Regulator. In the U.S., regulated interstate natural gas pipelines and regulated natural gas storage assets are subject to the authority of the Federal Energy Regulatory Commission (FERC). In Mexico, regulated natural gas pipelines are subject to the authority of the National Energy Commission (CNE). Rate-regulated accounting (RRA) standards may impact the timing of the recognition of certain revenues and expenses in TC Energy's rate-regulated businesses which may differ from that otherwise recognized in non-rate-regulated businesses to reflect the economic impact of the regulators' decisions regarding revenues and tolls. Regulatory assets represent costs that are expected to be recovered in customer rates in future periods and regulatory liabilities represent amounts that are expected to be returned to customers through future rate-setting processes. An operation qualifies for the use of RRA when it meets three criteria:

- a regulator must establish or approve the rates for the regulated services or activities
- the regulated rates must be designed to recover the cost of providing the services or products
- it is reasonable to assume that rates set at levels to recover the cost can be charged to and collected from customers because of the demand for services or products and the level of direct or indirect competition.

TC Energy's businesses that apply RRA currently include natural gas pipelines in Canada, U.S. and Mexico and regulated U.S. natural gas storage.

Revenue Recognition

The total consideration for services and products to which the Company expects to be entitled can include fixed and variable amounts. The Company has variable revenue that is subject to factors outside the Company's influence, such as market prices, actions of third parties and weather conditions. The Company considers some of this variable revenue to be constrained as it cannot be reliably estimated and, therefore, variable revenue is recognized only to the extent it is probable a significant reversal in cumulative revenue will not occur.

The Company's contracts with customers include natural gas pipelines capacity arrangements and transportation contracts, power generation contracts, natural gas storage and other contracts. Revenues from contracts with customers are recognized net of any commodity taxes collected from customers which are subsequently remitted to governmental authorities.

Revenues from non-lease components associated with a lease arrangement are recognized systematically over the term of the contract.

The majority of income earned from marketing activities, as it relates to the purchase and sale of natural gas and electricity, is recorded on a net basis in the month of delivery.

Canadian Natural Gas Pipelines

Capacity Arrangements and Transportation

Revenues from the Company's Canadian natural gas pipelines are generated from contractual arrangements for committed capacity and from the transportation of natural gas. Revenues earned from firm contracted capacity arrangements are recognized ratably over the term of the contract regardless of the amount of natural gas that is transported. Transportation revenues for interruptible or volumetric-based services are recognized when the service is performed.

Revenues from the Company's Canadian natural gas pipelines under federal jurisdiction are subject to regulatory decisions by the CER. The tolls charged on these pipelines are based on revenue requirements designed to recover the costs of providing natural gas capacity for transportation services, which includes a return of and on capital, as approved by the CER. The Company's Canadian natural gas pipelines are generally not subject to earnings volatility related to variances in revenues and costs. These variances, except as related to incentive arrangements, are generally subject to deferral treatment and are recovered or refunded in future tolls. Revenues recognized prior to a CER decision on rates for that period reflect the CER's last approved return on equity (ROE) assumptions. Adjustments to revenues are recorded when the CER decision is received. Canadian natural gas pipelines' revenues are invoiced and received on a monthly basis. The Company does not take ownership of the natural gas that it transports for customers.

U.S. Natural Gas Pipelines

Capacity Arrangements and Transportation

Revenues from the Company's U.S. natural gas pipelines are generated from contractual arrangements for committed capacity and from the transportation of natural gas. Revenues earned from firm contracted capacity arrangements are generally recognized ratably over the term of the contract regardless of the amount of natural gas that is transported. Transportation revenues for interruptible or volumetric-based services are recognized when the service is performed.

The Company's U.S. interstate natural gas pipelines are subject to FERC regulations and, as a result, a portion of revenues collected may be subject to refund if invoiced during an interim period when a rate proceeding is ongoing. Allowances for these potential refunds are recognized using management's best estimate based on the facts and circumstances of the proceeding. Any allowances that are recognized during the proceeding process are refunded or retained at the time a regulatory decision becomes final. U.S. natural gas pipelines' revenues are invoiced and received on a monthly basis. The Company does not take ownership of the natural gas that it transports for customers.

Natural Gas Storage and Other

Revenues from the Company's regulated U.S. natural gas storage services are generated mainly from firm committed capacity storage contracts. The performance obligation in these contracts is the reservation of a specified amount of capacity for storage including specifications with regard to the amount of natural gas that can be injected or withdrawn on a daily basis. Revenues are recognized ratably over the contract period for firm committed capacity regardless of the amount of natural gas that is stored, and when gas is injected or withdrawn for interruptible or volumetric-based services. Natural gas storage services revenues are invoiced and received on a monthly basis. The Company does not take ownership of the natural gas that it stores for customers.

The Company owns mineral rights associated with certain natural gas storage facilities. These mineral rights can be leased or contributed to producers of natural gas in return for a royalty interest which is recognized when natural gas and associated liquids are produced.

Mexico Natural Gas Pipelines

Capacity Arrangements and Transportation

Revenues from certain of the Company's Mexico natural gas pipelines are primarily collected based on negotiated firm capacity contracts and are generally recognized ratably over the term of the contract. Transportation revenues related to interruptible or volumetric-based services are recognized when the service is performed. Mexico natural gas pipelines' revenues are invoiced and received on a monthly basis. The Company does not take ownership of the natural gas that it transports for customers.

Other

The Company generates revenues from operating and maintenance services provided on leased pipelines. Revenues earned from these services are recognized ratably over the term of the contract.

Power and Energy Solutions

Power

Revenues from the Company's Power and Energy Solutions business are primarily derived from long-term contractual commitments to provide power capacity to meet the demands of the market and from the sale of electricity to both centralized markets and to customers. Power generation revenues also include revenues from the sale of steam to customers. Revenues and capacity payments are recognized as the services are provided and as electricity and steam is delivered. Power generation revenues are invoiced and received on a monthly basis.

Natural Gas Storage and Other

Non-regulated natural gas storage contracts include park, loan and term storage arrangements. Revenues are recognized as the services are provided. Term storage revenues are invoiced and received on a monthly basis. Revenues from ancillary services are recognized as the service is provided.

Cash and Cash Equivalents

The Company's Cash and cash equivalents consist of cash and highly liquid short-term investments with original maturities of three months or less and are recorded at cost, which approximates fair value.

Inventories

Inventories primarily consist of materials and supplies including spare parts and fuel, proprietary natural gas inventory in storage and emissions allowances and credits not held for compliance. The Company purchases certain emissions allowances and credits as part of bundled arrangements that also include the purchase of electricity for a fixed price. The cost allocated to emissions allowances and credits under such arrangements is based on observable market prices. Inventories are carried at the lower of cost and net realizable value.

Assets Held for Sale

The Company classifies assets as held for sale when management approves and commits to a formal plan to actively market a disposal group and expects the sale to close within the next 12 months. Upon classifying an asset as held for sale, the asset is recorded at the lower of its carrying amount or its estimated fair value, net of selling costs and any losses are recognized in net income. Gains related to the expected sale of these assets are not recognized until the transaction closes. Once an asset is classified as held for sale, depreciation expense is no longer recorded.

Plant, Property and Equipment

Natural Gas Pipelines

Plant, property and equipment for natural gas pipelines is carried at cost. Depreciation is calculated on a straight-line basis once the assets are ready for their intended use. Pipeline and compression equipment are depreciated at annual rates ranging from 0.625 per cent to 6.67 per cent and metering and other plant equipment are depreciated at various rates reflecting their estimated useful lives. The cost of major overhauls of equipment is capitalized and depreciated over the estimated service lives of the overhauls. The cost of regulated natural gas pipelines includes an allowance for funds used during construction (AFUDC) consisting of a debt component and an equity component based on the rate of return on rate base approved by regulators. AFUDC is reflected as an increase in the cost of the assets in Plant, property and equipment with a corresponding increase in Allowance for funds used during construction in the Consolidated statement of income. The equity component of AFUDC is a non-cash expenditure. Interest is capitalized during construction of non-regulated natural gas pipelines.

Natural gas pipelines' linepack and natural gas storage base gas are valued at cost and are maintained to ensure adequate pressure exists to transport natural gas through pipelines and deliver natural gas held in storage. Linepack and base gas are not depreciated.

When rate-regulated natural gas pipelines retire plant, property and equipment from service, the original book cost is removed from the gross plant amount and recorded as a reduction to accumulated depreciation with no amount recorded to net income. Costs incurred to remove plant, property and equipment from service, net of any salvage proceeds, are also recorded in accumulated depreciation.

Other

The Company participates as a working interest partner in the development of certain Marcellus and Utica acreage. The working interest allows the Company to invest in drilling activities in addition to receiving a royalty interest in well production. The Company uses the successful efforts method of accounting for natural gas and crude oil resulting from its portion of drilling activities. Capitalized well costs are depleted based on the units of production method.

Power and Energy Solutions

Plant, property and equipment for Power and Energy Solutions assets are recorded at cost and, once the assets are ready for their intended use, depreciated by major component on a straight-line basis over their estimated service lives at average annual rates ranging from two per cent to 20 per cent. Other equipment is depreciated at various rates reflecting their estimated useful lives. The cost of major overhauls of equipment is capitalized and depreciated over the estimated service lives of the overhauls. Interest is capitalized on facilities under construction. When these assets are retired from plant, property and equipment, the original book cost and related accumulated depreciation are derecognized and any gain or loss is recorded in net income.

Natural gas storage base gas, which is valued at original cost, represents gas volumes that are maintained to ensure adequate reservoir pressure exists to deliver gas held in storage. Base gas is not depreciated.

Corporate

Corporate plant, property and equipment is recorded at cost and depreciated on a straight-line basis over its estimated useful life at average annual rates ranging from four per cent to 20 per cent.

Capital Projects in Development

The Company capitalizes project costs once advancement of the project to construction stage is probable or costs are otherwise likely to be recoverable. The Company capitalizes interest costs for non-regulated projects in development and AFUDC for regulated projects in development. Capital projects in development are included in Other long-term assets on the Consolidated balance sheet. These represent larger projects that generally require regulatory or other approvals before physical construction can begin. Once approvals are received, projects are moved to plant, property and equipment under construction.

Leases

The Company determines if a contract contains a lease at inception, or upon modification, of a contract by using judgment in assessing the following aspects: 1) the contract specifies an identified asset which is physically distinct or, if not physically distinct, represents substantially all of the capacity of the asset; 2) the contract provides the customer with the right to obtain substantially all of the economic benefits from the use of the asset; and 3) the customer has the right to direct how and for what purpose the identified asset is used throughout the period of the contract.

If the contract is determined to contain a lease, further judgment is required to identify separate lease components of the arrangement by assessing whether the lessee can benefit from the right of use either on its own or together with other resources that are readily available to the lessee, as well as if the right of use is neither highly dependent on, nor highly interrelated, with the other rights to use underlying assets in the contract.

The Company considers non-lease components as distinct elements of a contract that are not related to the use of the leased asset. A good or service that is provided to a customer is distinct if: 1) the customer can benefit from the good or service either on its own or together with other resources that are readily available to the customer; and 2) the entity's promise to transfer the good or service to the customer is separately identifiable from other promises in the contract. The Company applies the practical expedient to not separate lease and non-lease components for all lessee contracts and facilities for which the Company is the lessor in an operating lease.

Lessee Accounting Policy

Operating leases are recognized as right-of-use (ROU) assets and included in Plant, property and equipment while corresponding liabilities are included in Accounts payable and other and Other long-term liabilities on the Consolidated balance sheet.

Operating lease ROU assets and operating lease liabilities are recognized based on the present value of the future minimum lease payments over the lease term at the commencement date of the lease agreement. Lease terms may include options to extend or terminate the lease when it is reasonably certain that the Company will exercise that option. As the Company's lease contracts do not provide an implicit interest rate, the Company uses its incremental borrowing rate based on the information available at commencement date, or upon modification of a lease, in determining the present value of future payments. Operating lease expense is recognized on a straight-line basis over the lease term and included in Plant operating costs and other in the Consolidated statement of income.

The Company applies the practical expedient to not recognize ROU assets or lease liabilities for leases that qualify for the short-term lease recognition exemption.

Lessor Accounting Policy

The Company provides transportation and other services on certain assets to customers according to long-term service agreements through sales-type and operating leases.

In a sales-type lease, the Company measures the total consideration within the contract at lease commencement, or upon modification of a lease. When a lease arrangement contains more than one lease and/or non-lease component, a portion of the contract consideration is allocated to each component based on the stand-alone selling price for each distinct service. The Company applies judgment to determine reasonable estimates of the expected future cost of satisfying the performance obligations of each service. The payments associated with lease components are apportioned between a reduction in the net investment in lease and sales-type lease income.

At lease commencement, the Company recognizes a net investment in lease equal to the present value of both the future lease payments and the estimated residual value of the leased asset discounted at the rate implicit in the lease. The plant, property and equipment of the leased asset is derecognized, with related gains/losses, if any, recognized in the Consolidated statement of income. Sales-type lease income is determined using the rate implicit in the lease and is recorded in Revenues.

The Company is the lessor within certain other contracts, including PPAs, that are accounted for as operating leases. In an operating lease, the leased asset remains capitalized in Plant, property and equipment on the Consolidated balance sheet and is depreciated over its useful life, while lease payments are recognized as revenue over the term of the lease on a straight-line basis. Variable lease payments are recognized as income in the period in which they occur.

Impairment of Long-Lived Assets

The Company reviews long-lived assets such as plant, property and equipment and capital projects in development for impairment whenever events or changes in circumstances indicate the carrying value may not be recoverable. If the total of the estimated undiscounted future cash flows for an asset within plant, property and equipment, or the estimated selling price of any long-lived asset is less than the carrying value of an asset, an impairment loss is recognized for the excess of the carrying value over the estimated fair value of the asset.

Impairment of Equity Method Investments

The Company reviews equity method investments for impairment when an event or change in circumstances has a significant adverse effect on the investment's fair value. Where the Company concludes an investment's fair value is below its carrying value, the Company then determines whether the impairment is other-than-temporary, and if so, an impairment loss is recognized for the excess of the carrying value over the estimated fair value of the investment, not exceeding the carrying value of the investment.

Acquisitions and Goodwill

The Company accounts for business combinations using the acquisition method of accounting and, accordingly, the assets and liabilities of the acquired entities are primarily measured at their estimated fair values at the date of acquisition. The excess of the fair value of the consideration transferred over the estimated fair value of the net assets acquired is classified as goodwill. Goodwill is not amortized and is tested for impairment on an annual basis, or more frequently if events or changes in circumstances indicate that it might be impaired.

The annual review for goodwill impairment is performed at the reporting unit level which is one level below the Company's operating segments. The Company can initially assess qualitative factors to determine whether events or changes in circumstances indicate that goodwill might be impaired. The factors the Company considers include, but are not limited to, macroeconomic conditions, industry and market considerations, current valuation multiples and discount rates, cost factors, historical and forecasted financial results and events specific to that reporting unit.

If the Company concludes that it is not more likely than not that the fair value of the reporting unit is greater than its carrying value, the Company will then perform a quantitative goodwill impairment test. The Company can elect to proceed directly to the quantitative goodwill impairment test for any of its reporting units. If the quantitative goodwill impairment test is performed, the Company compares the fair value of the reporting unit to its carrying value, including its goodwill. If the carrying value of a reporting unit exceeds its fair value, goodwill impairment is measured at the amount by which the reporting unit's carrying value exceeds its fair value. The fair value of a reporting unit is determined by using a discounted cash flow model which requires the use of assumptions that may include, but are not limited to, revenue and capital expenditure projections, valuation multiples and discount rates. The Company has elected to allocate goodwill impairment charges first to goodwill that is non-deductible for income tax purposes, with any remaining charge allocated to tax-deductible goodwill.

When a portion of a reporting unit that constitutes a business is disposed, goodwill associated with that business is included in the carrying amount of the business in determining the gain or loss on disposal. The amount of goodwill disposed is determined based on the relative fair values of the business to be disposed and the portion of the reporting unit that will be retained. A goodwill impairment test will be completed for the goodwill that will be retained.

Non-Controlling Interests

Non-controlling interests (NCI) represent third-party ownership interests in certain consolidated subsidiaries of the Company. Partial dispositions which result in a change in the Company's ownership interest, but do not result in a change in control, of a subsidiary that constitutes a business are accounted for as equity transactions. No gain or loss is recognized in earnings. At the time of partial disposition, NCI is recorded as the third party's ownership interest in the Company's carrying value of the net assets of the subsidiary. Any difference between the amount by which the NCI is adjusted and the fair value of the consideration paid or received is recognized in Additional paid-in capital and/or Retained earnings (Accumulated deficit).

Loans and Receivables

Loans receivable from affiliates and accounts receivable are measured at amortized cost.

Impairment of Financial Assets

The Company reviews financial assets, inclusive of net investment in leases and certain contract assets, carried at amortized cost for impairment using the lifetime expected loss of the financial asset at initial recognition and throughout the life of the financial asset. An expected credit loss (ECL) is calculated using a model and methodology based on assumptions and judgment considering historical data, current counterparty information as well as reasonable and supportable forecasts of future economic conditions.

The ECL is recognized in Plant operating costs and other in the Consolidated statement of income, and is presented on the Consolidated balance sheet as a reduction to the carrying value of the related financial asset.

Restricted Investments

The Company has certain investments that are restricted as to their withdrawal and use. These restricted investments are recorded at fair value on the Consolidated balance sheet.

As a result of the CER's Land Matters Consultation Initiative (LMCI), TC Energy is required to collect funds to cover estimated future pipeline abandonment costs for larger CER-regulated Canadian pipelines. Funds collected are placed in trusts that hold and invest the funds and are accounted for as restricted investments (LMCI restricted investments). LMCI restricted investments may only be used to fund the abandonment of the CER-regulated pipeline facilities, therefore, a corresponding regulatory liability is recorded on the Consolidated balance sheet.

The Company also has other restricted investments that have been set aside to fund insurance claim losses to be paid by the Company's wholly-owned captive insurance subsidiary.

Income Taxes

The Company uses the asset and liability method of accounting for income taxes. This method requires the recognition of deferred income tax assets and liabilities for future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases. Deferred income tax assets and liabilities are measured using enacted tax rates at the balance sheet date that are anticipated to apply to taxable income in the years in which temporary differences are expected to be reversed or settled. Changes to these balances are recognized in net income in the period in which they occur, except for changes in balances related to regulated natural gas pipelines which are deferred until they are refunded or recovered in tolls, as permitted by the regulator. Deferred income tax assets and liabilities are classified as non-current on the Consolidated balance sheet. The Company's exposure to uncertain tax positions is evaluated and a provision is made where it is more likely than not that this exposure will materialize.

Canadian income taxes are not provided for on the unremitted earnings of foreign investments that the Company does not intend to repatriate in the foreseeable future.

Any interest and/or penalty incurred related to income tax is reflected in Income tax expense.

Asset Retirement Obligations

The Company recognizes the fair value of a liability for asset retirement obligations (ARO) in the period in which it is incurred, when a legal obligation exists and a reasonable estimate of fair value can be made. The fair value is added to the carrying amount of the associated asset and the liability is accreted through charges to Plant operating costs and other in the Consolidated statement of income.

In determining the fair value of ARO, the following assumptions are used:

- the expected retirement date
- the scope and cost of abandonment and reclamation activities that are required
- appropriate inflation and discount rates.

The Company's AROs are substantially related to its power generation facilities. The scope and timing of asset retirements related to the Company's natural gas pipelines and storage facilities are indeterminable because the Company intends to operate them as long as there is supply and demand. As a result, the Company has not recorded an amount for ARO related to these assets.

Environmental Liabilities and Emission Allowances and Credits

The Company records liabilities on an undiscounted basis for environmental remediation efforts that are likely to occur and where the cost can be reasonably estimated. These estimates, including associated legal costs, are based on available information using existing technology and enacted laws and regulations and are subject to revision in future periods based on actual costs incurred or new circumstances. TC Energy evaluates recoveries from insurers and other third parties separately from the liability and, when recovery is probable, an asset is recorded separately from the associated liability. These recoveries are presented, along with environmental remediation costs, on a net basis in Plant operating costs and other in the Consolidated statement of income. Variations in one or more of the categories described above could result in additional costs such as fines, penalties and/or expenditures associated with litigation and settlement of claims with respect to environmental liabilities.

Emission allowances or credits purchased for compliance are recorded on the Consolidated balance sheet at historical cost and derecognized when they are utilized or cancelled/retired by government agencies. Compliance costs are expensed when incurred. Allowances granted to or internally generated by TC Energy are not attributed a value for accounting purposes. When required, TC Energy accrues emission liabilities on the Consolidated balance sheet using the best estimate of the amount required to settle the compliance obligation. Allowances and credits not used for compliance are sold and any gain or loss is recorded in Revenues within the Power and Energy Solutions segment in the Consolidated statement of income. The Company records allowances and credits held for compliance in Other current assets and Other long-term assets on the Consolidated balance sheet. Allowances and credits not held for compliance are classified as Inventories on the Consolidated balance sheet.

Stock Options and Other Compensation Programs

The Company no longer issues stock options to employees or officers. Stock options granted before 2024 were recorded using the fair value method. Under this method, compensation expense is measured at the grant date based on the fair value as calculated using a binomial model and is recognized on a straight-line basis over the vesting period with an offset to Additional paid-in capital. Forfeitures are accounted for when they occur. Upon exercise of stock options, amounts originally recorded against Additional paid-in capital are reclassified to Common shares on the Consolidated balance sheet.

The Company has medium-term incentive plans under which payments are made to eligible employees. The expense related to these incentive plans is accounted for on an accrual basis. Under these plans, benefits vest when certain conditions are met, including the employees' continued employment during a specified period and achievement of specified corporate performance targets.

Employee Post-Retirement Benefits

The Company sponsors defined benefit pension plans (DB Plans), defined contribution plans (DC Plans), savings plans and other post-retirement benefit plans (OPEB Plans). Contributions made by the Company to the DC Plans and savings plans are expensed in the period in which contributions are made. The cost of the DB Plans and OPEB Plans received by employees is actuarially determined using the projected benefit method pro-rated based on service and management's best estimate of expected plan investment performance, salary escalation, retirement age of employees and expected health care costs.

The DB Plans' assets are measured at fair value at December 31 of each year. The expected return on the DB Plans' assets is determined using market-related values based on a five-year moving average value for all of the DB Plans' assets. Past service costs are amortized over the expected average remaining service life (EARSL) of the employees. Adjustments arising from plan amendments are amortized on a straight-line basis over the EARSL of employees active at the date of amendment. The Company recognizes the overfunded or underfunded status of its DB Plans as an asset or liability, respectively, on its Consolidated balance sheet and recognizes changes in that funded status through Other comprehensive income (loss) (OCI) in the year in which the change occurs. The excess of net actuarial gains or losses over 10 per cent of the greater of the benefit obligation and the market-related value of the DB Plans' assets, if any, is amortized out of AOCI and into net income over the EARSL of the active employees. When the restructuring of a benefit plan gives rise to both a curtailment and a settlement, the curtailment is accounted for prior to the settlement.

For certain regulated operations, post-retirement benefit amounts are recoverable through tolls as benefits are funded. The Company records any unrecognized gains or losses or changes in actuarial assumptions related to these post-retirement benefit plans as either regulatory assets or liabilities. The regulatory assets or liabilities are amortized on a straight-line basis over the EARSL of active employees.

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 the Company or reporting subsidiary operates. This is referred to as the functional currency. Transactions denominated in foreign currencies are translated into 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 rate of exchange in effect at the balance sheet date whereas non-monetary assets and liabilities are translated at the historical rate of exchange in effect on the date of the transaction. Exchange gains and losses resulting from translation of monetary assets and liabilities are recorded in net income except for exchange gains and losses on any foreign currency debt related to Canadian regulated natural gas pipelines, which are deferred until they are refunded or recovered in tolls, as permitted by the CER.

Gains and losses arising from translation of foreign operations' functional currencies to the Company's Canadian dollar reporting currency are reflected in OCI until the operations are sold, at which time the gains and losses are reclassified to net income. For partial dispositions of foreign operations that do not result in a change of control, or dispositions of foreign operations other than by sale, gains and losses are reclassified within equity. Asset and liability accounts are translated at the rate of exchange in effect at the balance sheet date while revenues, expenses, gains and losses are translated at the exchange rate prevailing at the date of the transaction. The Company's U.S. dollar-denominated debt and certain derivative hedging instruments have been designated as a hedge of the net investment in foreign subsidiaries and, as a result, the unrealized foreign exchange gains and losses on the U.S. dollar-denominated debt and derivatives are also reflected in OCI.

Derivative Instruments and Hedging Activities

All derivative instruments are recorded on the Consolidated balance sheet at fair value, unless they qualify for and are designated under a normal purchase and normal sales exemption, or are considered to meet other permitted exemptions.

The Company applies hedge accounting to arrangements that qualify for and are designated for hedge accounting treatment. This includes fair value and cash flow hedges as well as hedges of foreign currency exposures of net investments in foreign operations. Hedge accounting is discontinued prospectively if the hedging relationship ceases to be effective or the hedging or hedged items cease to exist as a result of maturity, expiry, sale, termination, cancellation or exercise.

In a fair value hedging relationship, the carrying value of the hedged item is adjusted for changes in fair value attributable to the hedged risk and these changes are recognized in net income. Changes in the fair value of the hedged item, to the extent that the hedging relationship is effective, are offset by changes in the fair value of the hedging item, which are also recorded in net income. Changes in the fair value of foreign exchange and interest rate fair value hedges are recorded in Interest income and other and Interest expense, respectively. If hedge accounting is discontinued, the carrying value of the hedged item is no longer adjusted and the cumulative fair value adjustments to the carrying value of the hedged item are amortized to net income over the remaining term of the original hedging relationship.

In a cash flow hedging relationship, the change in the fair value of the hedging derivative is recognized in OCI. When hedge accounting is discontinued, the amounts recognized previously in AOCI are reclassified to Revenues, Interest expense and Interest income and other, as appropriate, during the periods when the variability in cash flows of the hedged item affects net income or as the original hedged item settles. Gains and losses on derivatives are reclassified immediately to net income from AOCI when the hedged item is sold or terminated early, or when it becomes probable that the anticipated transaction will not occur. Termination payments on interest rate derivatives are classified as a financing activity in the Consolidated statement of cash flows.

In hedging the foreign currency exposure of a net investment in a foreign operation, the foreign exchange gains and losses on the hedging instruments are recognized in OCI. The amounts recognized previously in AOCI are reclassified consistent with gains and losses arising from the translation of foreign operations, when the foreign operation is either entirely or partially disposed of.

In some cases, derivatives do not meet the specific criteria for hedge accounting treatment. In these instances, the changes in fair value are recorded in net income in the period of change.

Gains and losses arising from changes in the fair value of derivatives accounted for as part of RRA, including those that qualify for hedge accounting treatment, are refunded or recovered through the tolls charged by the Company. As a result, these gains and losses are deferred as regulatory liabilities or regulatory assets and are refunded to or collected from rate payers in subsequent periods when the derivative settles.

Derivatives embedded in other financial instruments or contracts (host instrument) are recorded as separate derivatives. Embedded derivatives are measured at fair value if their economic characteristics are not clearly and closely related to those of the host instrument, their terms are the same as those of a stand-alone derivative and the total contract is not held for trading or accounted for at fair value. When changes in the fair value of embedded derivatives are measured separately, they are included in net income.

Long-Term Debt Transaction Costs and Issuance Costs

The Company records long-term debt transaction costs and issuance costs as a deduction from the carrying amount of the related debt liability and amortizes these costs using the effective interest method except those related to the Canadian natural gas regulated pipelines, which continue to be amortized on a straight-line basis in accordance with the provisions of regulatory tolling mechanisms.

Guarantees

Upon issuance, the Company records the fair value of certain guarantees entered into by the Company on behalf of a partially-owned entity or by partially-owned entities for which contingent payments may be made. The fair value of these guarantees is estimated by discounting the cash flows that would be incurred by the Company if letters of credit were used in place of the guarantees as appropriate in the circumstances. Guarantees are recorded as an increase to Equity investments or Plant, property and equipment and a corresponding liability is recorded in Other long-term liabilities. The release from the obligation is recognized either over the term of the guarantee or upon expiration or settlement of the guarantee.

Variable Interest Entities

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. The assessment of whether an entity is a VIE and, if so, whether the Company is the primary beneficiary, is completed at the inception of the entity or at a reconsideration event.

Consolidated VIEs

The Company's consolidated VIEs consist of legal entities where the Company has a variable interest and for which it is considered the primary beneficiary. As the primary beneficiary, the Company has the power, through voting or similar rights, to direct the activities of the VIE that most significantly impact economic performance including: purchasing or selling significant assets; maintenance and operations of assets; incurring additional indebtedness; or determining the strategic operating direction of the entity. In addition, the Company has the obligation to absorb losses or the right to receive benefits from the consolidated VIE that could potentially be significant to the VIE.

Non-Consolidated VIEs

The Company's non-consolidated VIEs consist of legal entities where the Company has a variable interest but is not the primary beneficiary as it does not have the power (either explicit or implicit), through voting or similar rights, to direct the activities that most significantly impact the economic performance of these VIEs or where this power is shared with third parties. The Company contributes capital to these VIEs and receives ownership interests that provide it with residual claims on assets after liabilities are paid. Non-consolidated VIEs are accounted for as equity investments.

The Company's maximum exposure to loss is the maximum loss that could potentially be recorded through net income in future periods as a result of the Company's variable interest in a VIE.

3. ACCOUNTING CHANGES

Changes in Accounting Policies for 2025

Income Taxes

In December 2023, the FASB issued new guidance to enhance the transparency and usefulness of income tax disclosures through improvements to the rate reconciliation and income taxes paid information. The new guidance requires entities to disclose specific categories in the rate reconciliation and sets specific disaggregation requirements for reconciling items that meet certain thresholds. Additionally, entities are required to disclose disaggregated information on income taxes paid, income from continuing operations before tax and income tax expense from continuing operations. This new guidance was effective for annual periods beginning January 1, 2025. The Company adopted the guidance on a retrospective basis. The adoption of this guidance did not have a material impact on the Company's financial position or results of operations. Refer to Note 18, Income taxes, for additional information and the effects of the new guidance.

Future Accounting Changes

Disaggregation of Income Statement Expenses

In November 2024, the FASB issued new guidance requiring additional disclosure on the nature of expenses included in the income statement. The new standard requires disclosures about specific types of expenses included in the expense captions presented on the face of the income statement as well as disclosures about selling expenses. The new guidance is effective for annual periods beginning January 1, 2027 and interim periods beginning January 1, 2028. Early adoption is permitted. The guidance is applied prospectively with retrospective application permitted. The Company is currently assessing the impact of the standard on the Company's consolidated financial statements.

Internal-Use Software

In September 2025, the FASB issued updated guidance for accounting for internal-use software costs. The updated guidance removes references to project development stages and outlines revised guidance for when capitalization begins for internal-use software costs. The guidance is effective for annual and interim periods beginning January 1, 2028. Early adoption is permitted as of the beginning of an annual reporting period. The guidance can be applied prospectively, retrospectively, or with a modified transition approach. The Company is currently assessing the impact of the standard on the Company's consolidated financial statements.

Hedge Accounting Improvements

In November 2025, the FASB issued new guidance to further align hedge accounting with the economics of an entity's risk management activities. The amendments are intended to allow entities to achieve and maintain hedge accounting for highly effective hedges of forecasted transactions. The new guidance is effective for interim and annual reporting periods beginning January 1, 2027. Early adoption is permitted. The guidance is applied on a prospective basis for all hedging relationships that exist at the date of adoption. The Company is currently assessing the impact of the standard on the Company's consolidated financial statements.

Government Grants

In December 2025, the FASB established authoritative guidance on the recognition, measurement and presentation requirements for government grants received. The new guidance is effective for annual and interim periods beginning January 1, 2029. Early adoption is permitted. The guidance can be applied with a modified prospective, a modified retrospective, or a retrospective approach. The Company is currently assessing the impact of the standard on the Company's consolidated financial statements.

4. DISCONTINUED OPERATIONS

Spinoff of Liquids Pipelines Business

On October 1, 2024, TC Energy completed the spinoff of its Liquids Pipelines business. Pursuant to the Spinoff Transaction, TC Energy and South Bow executed a series of agreements to outline the parameters and guidelines that govern their ongoing relationship, including a Transition Services Agreement, Tax Matters Agreement and a Separation Agreement.

The Transition Services Agreement was established to specify certain services that TC Energy will provide to South Bow for a period of up to two years.

The Tax Matters Agreement governs TC Energy and South Bow's tax rights and obligations after the Spinoff Transaction. The agreement imposes certain restrictions on both TC Energy and South Bow in order to preserve the tax-free status of the spinoff. In the event the Spinoff Transaction is not tax-free, the agreement allocates tax liabilities by generally assigning responsibility to either TC Energy or South Bow to the extent that the failure to qualify is attributable to actions, events or transactions, or a breach of the representations or covenants made by that entity.

The Separation Agreement set forth the terms of the separation of the Liquids Pipelines business from the business of TC Energy, including the transfer of certain assets related to the Liquids Pipelines business from TC Energy to South Bow and the allocation of certain liabilities and obligations related to the Liquids Pipelines business between TC Energy and South Bow.

During 2025, TC Energy reached an agreement with South Bow with respect to liabilities the Company indemnified South Bow for under the Separation Agreement, releasing the Company from those liabilities. Inclusive of the recognition of the settlement, a net loss from discontinued operations of $183 million, net of tax was recognized. Payments related to the settlement commenced in fourth quarter 2025 and will be completed in 2026.

In addition, the Company revised its estimate of future recoveries, resulting in a $29 million impairment, which was included in Net income (loss) from discontinued operations, net of tax in the Consolidated statement of income.

Separation Costs

Liquids Pipelines business separation costs primarily include internal costs related to separation activities, legal, income tax, audit and other consulting fees, insurance provisions and net financial charges related to debt issued and held in escrow. For the years ended December 31, 2024 and 2023, Liquids Pipelines business separation costs of $197 million ($167 million after tax) and $40 million ($34 million after tax), respectively, were included in Net income (loss) from discontinued operations, net of tax in the Consolidated statement of income. There were no separation costs recognized for the year ended December 31, 2025.

Pensions

As part of the Spinoff Transaction, certain TC Energy employees became employees of South Bow. Prior to the Spinoff Transaction, these employees in Canada and the U.S. participated in DB Plans, DC Plans and savings plans, as applicable. Effective October 1, 2024, the benefit obligations under the DB Plans in respect of the employees moving from TC Energy to South Bow were transferred to South Bow. An asset transfer application related to the Canadian DB Plan outlining the proposed transfer of assets from TC Energy to South Bow has received regulatory approval. During the year ended December 31, 2025, $105 million was transferred to South Bow. As at December 31, 2025, $17 million of assets in the Canadian DB Plan remain in the TC Energy DB Plan trust and are reflected as Current assets of discontinued operations with a corresponding obligation to South Bow reflected as Current liabilities of discontinued operations on the Consolidated balance sheet. The Company expects the remaining assets to be fully transferred mid-2026. As at December 31, 2024, the assets related to the U.S. DB Plan were fully transferred to South Bow.

South Bow Debt

On August 28, 2024, South Bow Canadian Infrastructure Holdings Ltd. and 6297782 LLC, two wholly-owned subsidiaries of the Company at the time, completed an offering of approximately $7.9 billion Canadian-dollar equivalent of senior unsecured notes and junior subordinated notes. Approximately $6.2 billion Canadian-dollar equivalent of the net proceeds was placed in escrow pending the completion of the Spinoff Transaction on October 1, 2024 and US$1.3 billion of senior unsecured notes were used to repay a TransCanada PipeLines Limited (TCPL) term loan. Upon completion of the Spinoff Transaction, the escrowed funds were released to South Bow and used to repay indebtedness owed by South Bow and its subsidiaries to TC Energy and its subsidiaries.

Presentation of Discontinued Operations

As described in Note 2, Accounting policies, upon completion of the Spinoff Transaction, the Liquids Pipelines business was accounted for as discontinued operations. The Company's presentation of discontinued operations includes revenues and expenses directly attributable to the Liquids Pipelines business.

Prior year comparatives present the Liquids Pipelines business as discontinued operations.

Income from Discontinued Operations

year ended December 31 (millions of Canadian $)	**2025**	**2024**	**2023**
Revenues	**—**	2,217	2,667
Income (Loss) from Equity Investments	**—**	50	67
Operating and Other Expenses			
Plant operating costs and other	**216**	806	814
Commodity purchases resold	**—**	387	437
Property taxes	**—**	84	116
Depreciation and amortization	**—**	253	332
Asset impairment charge and other	**29**	21	(4)
	245	1,551	1,695
Segmented Earnings (Losses) from Discontinued Operations	**(245)**	716	1,039
Financial Charges			
Interest expense	**—**	218	297
Interest income and other	**(28)**	(21)	30
	(28)	197	327
Income (Loss) from Discontinued Operations before Income Taxes	**(217)**	519	712
Income tax expense (recovery)	**(5)**	124	100
Net Income (Loss) from Discontinued Operations, Net of Tax	**(212)**	395	612

Assets and Liabilities of Discontinued Operations

at December 31 (millions of Canadian $)	2025	2024
ASSETS		
Current Assets		
Other current assets	**197**	235
	197	235
Other Long-Term Assets	**—**	136
	197	371
LIABILITIES		
Current Liabilities		
Accounts payable and other	**181**	170
	181	170
Other Long-Term Liabilities	**—**	110
	181	280

The Spinoff Transaction resulted in derecognition of the net assets of the Liquids Pipelines segment in the amount of $3,691 million. The reduction in net assets was reflected as a $2,950 million decrease in Retained earnings (Accumulated deficit) and a $741 million decrease in AOCI for the year ended December 31, 2024.

For the year ended December 31, 2025, the Company recorded $542 million related to the Spinoff Transaction as an out-of-period adjustment to reclassify a pro rata portion of its net investment hedge losses recorded in AOCI to Retained earnings (Accumulated deficit). Refer to Note 2, Accounting policies, for additional information.

Cash Flows from Discontinued Operations

year ended December 31 (millions of Canadian $)	2025	2024	2023
Net cash (used in) provided by operations	**(185)**	670	1,026
Net cash (used in) provided by investing activities	**24**	(89)	87

5. SEGMENTED INFORMATION

The Company's chief operating decision maker is the President and Chief Executive Officer. The chief operating decision maker uses segmented earnings (losses) to assess the performance of the business segments, assist with capital investment decisions and benchmark to TC Energy's competitors.

Information regarding the Company's business segments is as follows:

year ended December 31, 2025 (millions of Canadian $)	Canadian Natural Gas Pipelines	U.S. Natural Gas Pipelines	Mexico Natural Gas Pipelines	Power and Energy Solutions	Corporate [1]	Total
Revenues	5,785	7,145	1,450	845	14	15,239
Intersegment revenues[2]	—	99	—	52	(151)	—
	5,785	7,244	1,450	897	(137)	15,239
Income (loss) from equity investments	112	301	94	767	—	1,274
Operating costs[2]	(2,210)	(2,581)	(262)	(778)	123	(5,708)
Depreciation and amortization	(1,523)	(1,037)	(96)	(113)	—	(2,769)
Segmented Earnings (Losses)	2,164	3,927	1,186	773	(14)	8,036
Interest expense						(3,407)
Allowance for funds used during construction						453
Foreign exchange gains (losses), net						157
Interest income and other						205
Income (Loss) from Continuing Operations before Income Taxes						5,444
Income tax (expense) recovery from continuing operations						(1,138)
Net Income (Loss) from Continuing Operations						4,306
Net Income (Loss) from Discontinued Operations, Net of Tax						(212)
Net Income (Loss)						4,094
Net (income) loss attributable to non-controlling interests						(575)
Net Income (Loss) Attributable to Controlling Interests						3,519
Preferred share dividends						(119)
Net Income (Loss) Attributable to Common Shares						3,400
Capital Spending[3]						
Capital expenditures	1,340	3,316	522	61	31	5,270
Capital projects in development	—	—	—	16	—	16
Contributions to equity investments	65	141	—	845	—	1,051
	1,405	3,457	522	922	31	6,337

1 Includes intersegment eliminations.

2 The Company records intersegment sales at contracted rates. For segmented reporting, these transactions are included as Intersegment revenues in the segment providing the service and Operating costs in the segment receiving the service. These transactions are eliminated on consolidation. Intersegment profit is recognized when the product or service has been provided to third parties or otherwise realized.

3 Included in Investing activities in the Consolidated statement of cash flows.

year ended December 31, 2024 (millions of Canadian $)	Canadian Natural Gas Pipelines	U.S. Natural Gas Pipelines	Mexico Natural Gas Pipelines	Power and Energy Solutions	Corporate[1]	Total
Revenues	5,600	6,339	870	954	8	13,771
Intersegment revenues[2]	—	99	—	49	(148)	—
	5,600	6,438	870	1,003	(140)	13,771
Income (loss) from equity investments	34	341	283	900	—	1,558
Operating costs[2]	(2,246)	(2,381)	(132)	(700)	9[3]	(5,450)
Depreciation and amortization	(1,382)	(955)	(92)	(101)	(5)[3]	(2,535)
Other segment items[4]	10	610	—	—	—	620
Segmented Earnings (Losses)	2,016	4,053	929	1,102	(136)	7,964
Interest expense						(3,019)
Allowance for funds used during construction						784
Foreign exchange gains (losses), net						(147)
Interest income and other						324
Income (Loss) from Continuing Operations before Income Taxes						5,906
Income tax (expense) recovery from continuing operations						(922)
Net Income (Loss) from Continuing Operations						4,984
Net income (loss) from Discontinued Operations, Net of Tax						395
Net Income (Loss)						5,379
Net Income (loss) attributable to non-controlling interests						(681)
Net Income (Loss) Attributable to Controlling Interests						4,698
Preferred share dividends						(104)
Net Income (Loss) Attributable to Common Shares						4,594
Capital Spending[5]						
Capital expenditures	1,273	2,568	2,228	62	50	6,181
Capital projects in development	—	5	—	45	—	50
Contributions to equity investments[6]	827	2	—	717	—	1,546
	2,100	2,575	2,228	824	50	7,777
Discontinued operations						127
						7,904

1 Includes intersegment eliminations.

2 The Company records intersegment sales at contracted rates. For segmented reporting, these transactions are included as Intersegment revenues in the segment providing the service and Operating costs in the segment receiving the service. These transactions are eliminated on consolidation. Intersegment profit is recognized when the product or service has been provided to third parties or otherwise realized.

3 Includes shared costs and depreciation previously allocated to the Liquids Pipelines segment. Refer to Note 4, Discontinued operations, for additional information.

4 Other segment items include a Net gain (loss) on sale of assets.

5 Included in Investing activities in the Consolidated statement of cash flows.

6 Contributions to equity investments in the Canadian Natural Gas Pipelines segment of $3.1 billion are offset by the equivalent amount in Other distributions from equity investments, although they are reported on a gross basis in the Company's Consolidated statement of cash flows. Refer to Note 10, Equity investments, for additional information.

year ended December 31, 2023 (millions of Canadian $)	Canadian Natural Gas Pipelines	U.S. Natural Gas Pipelines	Mexico Natural Gas Pipelines	Power and Energy Solutions	Corporate [1]	Total
Revenues	5,173	6,229	846	1,019	—	13,267
Intersegment revenues[2]	—	101	—	22	(123)	—
	5,173	6,330	846	1,041	(123)	13,267
Income (loss) from equity investments	220	324	78	688	—	1,310
Impairment of equity investment	(2,100)	—	—	—	—	(2,100)
Operating costs[2]	(2,058)	(2,189)	(39)	(633)	(15) [3]	(4,934)
Depreciation and amortization	(1,325)	(934)	(89)	(92)	(6) [3]	(2,446)
Segmented Earnings (Losses)	(90)	3,531	796	1,004	(144)	5,097
Interest expense						(2,966)
Allowance for funds used during construction						575
Foreign exchange gains (losses), net						320
Interest income and other						272
Income (Loss) from Continuing Operations before Income Taxes						3,298
Income tax (expense) recovery from continuing operations						(842)
Net Income (Loss) from Continuing Operations						2,456
Net Income (Loss) from Discontinued Operations, Net of Tax						612
Net Income (Loss)						3,068
Net (income) loss attributable to non-controlling interests						(146)
Net Income (Loss) Attributable to Controlling Interests						2,922
Preferred share dividends						(93)
Net Income (Loss) Attributable to Common Shares						2,829
Capital Spending[4]						
Capital expenditures	2,953	2,536	2,292	144	33	7,958
Capital projects in development	—	—	—	142	—	142
Contributions to equity investments	3,231	124	—	794	—	4,149
	6,184	2,660	2,292	1,080	33	12,249
Discontinued operations						49
						12,298

1 Includes intersegment eliminations.

2 The Company records intersegment sales at contracted rates. For segmented reporting, these transactions are included as Intersegment revenues in the segment providing the service and Operating costs in the segment receiving the service. These transactions are eliminated on consolidation. Intersegment profit is recognized when the product or service has been provided to third parties or otherwise realized.

3 Includes shared costs and depreciation previously allocated to the Liquids Pipelines segment. Refer to Note 4, Discontinued operations, for additional information.

4 Included in Investing activities in the Consolidated statement of cash flows.

at December 31 (millions of Canadian $)	2025	2024
Total Assets by Segment		
Canadian Natural Gas Pipelines	**31,371**	31,167
U.S. Natural Gas Pipelines	**56,617**	56,304
Mexico Natural Gas Pipelines	**16,342**	15,995
Power and Energy Solutions	**10,764**	10,217
Corporate	**3,460**	4,189
	118,554	117,872
Discontinued Operations	**197**	371
	118,751	118,243

Geographic Information

year ended December 31 (millions of Canadian $)	2025	2024	2023
Revenues			
Canada – domestic	**5,617**	5,579	5,337
Canada – export	**968**	953	821
United States	**7,204**	6,369	6,263
Mexico	**1,450**	870	846
	15,239	13,771	13,267

at December 31 (millions of Canadian $)	2025	2024
Plant, Property and Equipment		
Canada	**26,078**	26,354
United States	**40,976**	40,580
Mexico	**4,000**	10,567
	71,054	77,501

6. REVENUES

Disaggregation of Revenues

year ended December 31, 2025 (millions of Canadian $)	Canadian Natural Gas Pipelines	U.S. Natural Gas Pipelines	Mexico Natural Gas Pipelines	Power and Energy Solutions	Total
Revenues from contracts with customers					
Capacity arrangements and transportation	**5,785**	**5,698**	**445**	**—**	**11,928**
Power generation	**—**	**—**	**—**	**236**	**236**
Natural gas storage and other[1]	**—**	**1,141**	**218**	**440**	**1,799**
	5,785	**6,839**	**663**	**676**	**13,963**
Sales-type lease income[2]	**—**	**—**	**787**	**—**	**787**
Other revenues[3]	**—**	**306**	**—**	**169**	**475**
	5,785	**7,145**	**1,450**	**845**	**15,225**
Corporate revenues[4]					**14**
					15,239

1 The Mexico Natural Gas Pipelines segment includes $192 million of revenues generated from non-lease components for the provision of operating and maintenance services with respect to sales-type leases on the in-service Transportadora de Gas Natural de La Huasteca (TGNH) pipelines. Refer to Note 9, Leases, for additional information.

2 Represents the sales-type lease income on the in-service TGNH pipelines. Refer to Note 9, Leases, for additional information.

3 Includes income from the Company's marketing activities, financial instruments and operating lease income. Refer to Note 9, Leases, and Note 27, Risk management and financial instruments, for additional information.

4 Revenues generated from the Transition Services Agreement with South Bow. Refer to Note 4, Discontinued operations, for additional information.

year ended December 31, 2024 (millions of Canadian $)	Canadian Natural Gas Pipelines	U.S. Natural Gas Pipelines	Mexico Natural Gas Pipelines	Power and Energy Solutions	Total
Revenues from contracts with customers					
Capacity arrangements and transportation	5,586	5,382	438	—	11,406
Power generation	—	—	—	266	266
Natural gas storage and other[1,2]	14	869	124	383	1,390
	5,600	6,251	562	649	13,062
Sales-type lease income[3]	—	—	308	—	308
Other revenues[4]	—	88	—	305	393
	5,600	6,339	870	954	13,763
Corporate revenues[5]					8
					13,771

1 The Canadian Natural Gas Pipelines segment includes $14 million of fee revenues from an affiliate related to the development and construction of the Coastal GasLink pipeline project, which is 35 per cent owned by TC Energy.

2 The Mexico Natural Gas Pipelines segment includes $98 million of revenues generated from non-lease components for the provision of operating and maintenance services with respect to sales-type leases on the in-service TGNH pipelines. Refer to Note 9, Leases, for additional information.

3 Represents the sales-type lease income on the in-service TGNH pipelines. Refer to Note 9, Leases, for additional information.

4 Includes income from the Company's marketing activities, financial instruments and operating lease income. Refer to Note 9, Leases, and Note 27, Risk management and financial instruments, for additional information.

5 Includes $7 million of revenues generated from the Transition Services Agreement with South Bow. Refer to Note 4, Discontinued operations, for additional information.

year ended December 31, 2023 (millions of Canadian $)	Canadian Natural Gas Pipelines	U.S. Natural Gas Pipelines	Mexico Natural Gas Pipelines	Power and Energy Solutions	Total
Revenues from contracts with customers					
Capacity arrangements and transportation	5,141	5,107	442	—	10,690
Power generation	—	—	—	427	427
Natural gas storage and other[1,2]	32	874	125	363	1,394
	5,173	5,981	567	790	12,511
Sales-type lease income[3]	—	—	279	—	279
Other revenues[4]	—	248	—	229	477
	5,173	6,229	846	1,019	13,267

1 The Canadian Natural Gas Pipelines segment includes $31 million of fee revenues from an affiliate related to the development and construction of the Coastal GasLink pipeline project which is 35 per cent owned by TC Energy.
2 The Mexico Natural Gas Pipelines segment includes $97 million of revenues generated from non-lease components for the provision of operating and maintenance services with respect to sales-type leases on the in-service TGNH pipelines. Refer to Note 9, Leases, for additional information.
3 Represents the sales-type lease income on the in-service TGNH pipelines. Refer to Note 9, Leases, for additional information.
4 Includes income from the Company's marketing activities, financial instruments and operating lease income. Refer to Note 9, Leases, and Note 27, Risk management and financial instruments, for additional information.

Contract Balances

at December 31 (millions of Canadian $)	2025	2024	Affected line item on the Consolidated balance sheet
Receivables from contracts with customers	**1,822**	1,452	Accounts receivable
Contract assets (Note 7)	**216**	165	Other current assets
Long-term contract assets (Note 14)	**627**	608	Other long-term assets
Contract liabilities[1] (Note 16)	**46**	30	Accounts payable and other

1 During the year ended December 31, 2025, $21 million (2024 – $41 million) of revenues were recognized, which were included in contract liabilities and long-term contract liabilities at the beginning of the year.

Contract assets and long-term contract assets primarily relate to the Company’s right to revenues for services completed but not invoiced at the reporting date on long-term committed capacity natural gas pipelines contracts. The change in contract assets is primarily related to the transfer to Accounts receivable when these rights become unconditional and the customer is invoiced, as well as the recognition of additional revenues that remain to be invoiced. Contract liabilities primarily represent unearned revenue for contracted services.

Future Revenues from Remaining Performance Obligations

As at December 31, 2025, future revenues from long-term pipeline capacity arrangements and transportation as well as natural gas storage and other contracts extending through 2055 are approximately $33.8 billion, of which approximately $7.0 billion is expected to be recognized in 2026.

A significant portion of the Company's revenues are not included in the future revenue disclosure above, as the Company has elected the following disclosure exemptions:

- revenues related to flow-through operating costs, or other similar variable consideration, that are recognized at the amount for which the Company has the right to invoice the customer
- variable consideration relating to interruptible transportation service revenues and power generation revenues where there is uncertainty in estimating the amount of future revenue
- revenues for periods extending beyond the current rate settlement term for the Company’s U.S. natural gas pipelines' regulated transportation and storage contracts where the maximum tariff rate is to be collected from shippers
- revenues for periods extending beyond the current rate settlement term for the Company's Canadian natural gas pipelines' regulated firm capacity contracts
- revenues related to assets under construction, which are recognized when the asset is placed in service.

7. OTHER CURRENT ASSETS

at December 31		
(millions of Canadian $)	**2025**	**2024**
Net investment in leases (Note 9)	**1,256**	333
Fair value of derivative instruments (Note 27)	**438**	347
Contract assets (Note 6)	**216**	165
Cash provided as collateral	**93**	128
Prepaid expenses	**82**	86
Emissions credits	**67**	75
Regulatory assets (Note 12)	**58**	123
Other	**165**	82
	2,375	1,339

8. PLANT, PROPERTY AND EQUIPMENT

at December 31	2025			2024		
(millions of Canadian $)	Cost	Accumulated Depreciation	Net Book Value	Cost	Accumulated Depreciation	Net Book Value
Canadian Natural Gas Pipelines						
NGTL System						
Pipeline	**20,806**	**8,037**	**12,769**	20,497	7,413	13,084
Compression	**7,277**	**2,732**	**4,545**	7,146	2,497	4,649
Metering and other	**1,685**	**903**	**782**	1,668	883	785
	29,768	**11,672**	**18,096**	29,311	10,793	18,518
Under construction	**663**	**—**	**663**	503	—	503
	30,431	**11,672**	**18,759**	29,814	10,793	19,021
Canadian Mainline						
Pipeline	**11,126**	**8,355**	**2,771**	10,907	8,165	2,742
Compression	**4,661**	**3,500**	**1,161**	4,540	3,448	1,092
Metering and other	**797**	**344**	**453**	749	331	418
	16,584	**12,199**	**4,385**	16,196	11,944	4,252
Under construction	**121**	**—**	**121**	163	—	163
	16,705	**12,199**	**4,506**	16,359	11,944	4,415
Other Canadian Natural Gas Pipelines[1]						
Other	**2,947**	**1,777**	**1,170**	2,927	1,742	1,185
Under construction	**19**	**—**	**19**	31	—	31
	2,966	**1,777**	**1,189**	2,958	1,742	1,216
	50,102	**25,648**	**24,454**	49,131	24,479	24,652
U.S. Natural Gas Pipelines						
Columbia Gas						
Pipeline	**14,996**	**1,610**	**13,386**	14,826	1,472	13,354
Compression	**6,169**	**741**	**5,428**	6,153	677	5,476
Metering and other	**4,529**	**502**	**4,027**	4,570	455	4,115
	25,694	**2,853**	**22,841**	25,549	2,604	22,945
Under construction	**675**	**—**	**675**	891	—	891
	26,369	**2,853**	**23,516**	26,440	2,604	23,836
ANR						
Pipeline	**3,092**	**744**	**2,348**	2,477	745	1,732
Compression	**4,933**	**948**	**3,985**	4,446	938	3,508
Metering and other	**1,867**	**509**	**1,358**	1,832	521	1,311
	9,892	**2,201**	**7,691**	8,755	2,204	6,551
Under construction	**362**	**—**	**362**	853	—	853
	10,254	**2,201**	**8,053**	9,608	2,204	7,404

at December 31	2025			2024		
(millions of Canadian $)	Cost	Accumulated Depreciation	Net Book Value	Cost	Accumulated Depreciation	Net Book Value
Other U.S. Natural Gas Pipelines						
Columbia Gulf	**4,427**	**274**	**4,153**	4,127	304	3,823
GTN	**3,325**	**1,476**	**1,849**	3,405	1,467	1,938
Great Lakes	**2,577**	**1,509**	**1,068**	2,602	1,537	1,065
Other[2]	**1,646**	**655**	**991**	1,695	628	1,067
	11,975	**3,914**	**8,061**	11,829	3,936	7,893
Under construction	**643**	**—**	**643**	694	—	694
	12,618	**3,914**	**8,704**	12,523	3,936	8,587
	49,241	**8,968**	**40,273**	48,571	8,744	39,827
Mexico Natural Gas Pipelines[3]						
Pipeline	**2,468**	**545**	**1,923**	2,590	523	2,067
Compression	**449**	**113**	**336**	476	107	369
Metering and other	**394**	**107**	**287**	398	99	299
	3,311	**765**	**2,546**	3,464	729	2,735
Under construction	**1,454**	**—**	**1,454**	7,807	—	7,807
	4,765	**765**	**4,000**	11,271	729	10,542
Power and Energy Solutions						
Natural Gas Power Generation	**1,322**	**719**	**603**	1,273	671	602
Natural Gas Storage and Other	**887**	**308**	**579**	873	281	592
Renewable Power Generation	**737**	**83**	**654**	779	54	725
	2,946	**1,110**	**1,836**	2,925	1,006	1,919
Under construction	**56**	**—**	**56**	56	—	56
	3,002	**1,110**	**1,892**	2,981	1,006	1,975
Corporate	**895**	**460**	**435**	944	439	505
	108,005	**36,951**	**71,054**	112,898	35,397	77,501

1 Includes Foothills, Ventures LP and Great Lakes Canada.

2 Includes North Baja, Tuscarora, Louisiana Intrastate, Crossroads, U.S. Energy Marketing and mineral rights business.

3 During the year ended December 31, 2025, the Company derecognized $6,595 million (2024 – nil) of Plant, property and equipment and recorded a corresponding asset to net investment in leases for the in-service TGNH pipelines. Refer to Note 9, Leases, for additional information.

9. LEASES

As a Lessee

The Company has operating leases for corporate offices, other various premises, equipment and land. Some leases have an option to renew for periods of one to 25 years, and some may include options to terminate the lease within one year or when certain conditions are met. Payments due under lease contracts include fixed payments plus, for many of the Company's leases, variable payments such as a proportionate share of the buildings' property taxes, insurance and common area maintenance. The Company subleases some of the leased premises.

Operating lease cost was as follows:

year ended December 31 (millions of Canadian $)	2025	2024
Operating lease cost[1]	**112**	117
Sublease income	**(5)**	(6)
Net operating lease cost	**107**	111

1 Includes short-term leases and variable lease costs.

Other information related to operating leases is noted in the following tables:

year ended December 31 (millions of Canadian $)	2025	2024
Cash paid for amounts included in the measurement of operating lease liabilities	**76**	74
ROU assets obtained in exchange for new operating lease liabilities	**18**	96

at December 31	2025	2024
Weighted average remaining lease term	**11 years**	13 years
Weighted average discount rate	**3.4%**	3.3%

Maturities of operating lease liabilities are as follows:

at December 31 (millions of Canadian $)	2025	2024
Less than one year	**73**	73
One to two years	**66**	73
Two to three years	**63**	66
Three to four years	**63**	64
Four to five years	**59**	63
More than five years	**185**	275
Total operating lease payments	**509**	614
Imputed interest	**(78)**	(103)
Operating lease liabilities	**431**	511

The amounts recognized on TC Energy's Consolidated balance sheet for its operating lease liabilities were as follows:

at December 31 (millions of Canadian $)	2025	2024
Accounts payable and other (Note 16)	**61**	60
Other long-term liabilities (Note 17)	**370**	451
	431	511

As at December 31, 2025, the carrying value of the ROU assets recorded under operating leases was $402 million (2024 – $480 million) and is included in Plant, property and equipment on the Consolidated balance sheet.

As a Lessor

Operating Leases

The Grandview and Bécancour power plants in the Power and Energy Solutions segment are accounted for as operating leases. The Company has long-term PPAs for the sale of power from these assets which expire between 2026 and 2035.

Some operating leases contain variable lease payments that are based on operating hours and the reimbursement of variable costs, and options to purchase the underlying asset at fair value or based on a formula considering the remaining fixed payments. Lessees have rights under some leases to terminate under certain circumstances.

The fixed portion of the operating lease income recorded by the Company for the year ended December 31, 2025 was $109 million (2024 – $114 million; 2023 – $112 million).

Future lease payments to be received under operating leases are as follows:

at December 31 (millions of Canadian $)	2025	2024
Less than one year	**80**	107
One to two years	**9**	76
Two to three years	**10**	9
Three to four years	**10**	10
Four to five years	**10**	10
More than five years	**45**	55
	164	267

At December 31, 2025, the cost and accumulated depreciation for facilities accounted for as operating leases was $697 million and $371 million, respectively (2024 – $697 million and $351 million, respectively).

Sales-Type Leases

The Tamazunchale, Villa de Reyes, Tula and Southeast Gateway pipelines are part of a U.S. dollar-denominated take-or-pay Transportation Service Agreement (TSA) that extends through 2055 between TGNH and the Comisión Federal de Electricidad (CFE).

The consolidated TSA contains multiple lease and non-lease components. The lease components within the TSA represent the capacity available to the CFE provided by the in-service pipelines within TGNH at December 31, 2025. The non-lease components represent the Company’s services with respect to operation and maintenance of the TGNH pipelines in service. The Company allocated a portion of the contract consideration to non-lease components for the provision of operating and maintenance services based on the stand-alone selling price using an expected cost plus margin approach. The remaining consideration was allocated to the lease components using the residual approach due to uncertainty surrounding the stand-alone selling price.

Transportadora de Gas Natural de la Huasteca
In September 2025, TC Energy entered into a factoring arrangement with the CFE and a major domestic bank in Mexico to factor monthly invoices for services provided on the TGNH system in 2025. Invoices for August to October were factored to the bank without recourse to TC Energy and TC Energy continued to receive invoiced amounts within the contractual payment period.

The factoring arrangement resulted in a lease modification for accounting purposes of the existing TGNH TSA with the CFE, with no change to the lease classification upon reassessment. As such, the Company reallocated contract consideration to the lease and non-lease components of the contract using an expected cost plus margin approach based on the updated operating and maintenance services stand-alone selling price for each non-lease component as of the date of modification. The residual amount of consideration from this process was then allocated to the lease component. The change in allocation was accounted for prospectively. The rate implicit in the lease was adjusted to the rate at which the modified net investment in lease equaled the carrying value of the net investment in lease directly prior to the effective date of the modification.

Under lease accounting, TC Energy recorded factored amounts in Accounts payable and other, and the corresponding receivables were not derecognized on the Consolidated balance sheet. Cash received from the factoring arrangement were included in Financing activities in the Consolidated statement of cash flows. During 2025, TC Energy assigned and received payment for receivables having an aggregate face value of $351 million (US$251 million).

Southeast Gateway Pipeline
During second quarter 2025, the Company announced the completion of the Southeast Gateway pipeline. The Company determined that the pipeline is a sales-type lease between TGNH and the CFE that commenced when the asset was made available to the customer. At the inception of the agreement in 2022 and as revised in third quarter 2025 when the Company entered into a factoring arrangement with the CFE, the Company allocated the expected contract consideration to the non-lease component for the provisioning of operating and maintenance services based on the estimated stand-alone selling price using an expected cost plus margin approach. The residual amount of consideration from this process was then allocated to the lease component. The Company's estimate of future operating costs influenced the allocation of contract consideration between lease and non-lease components, the timing of income recognized under the contract and the calculation of the rate implicit in the lease.

The TGNH pipelines, which includes the Southeast Gateway pipeline, are rate-regulated and the tolls are designed to recover the cost of providing service. On this basis, the Company applied judgment to determine that, at the inception of the lease arrangement, the fair value of the underlying assets approximated the carrying value and the residual value approximated the remaining carrying value at the end of the lease term. The fair value was a non-recurring measurement classified in Level III of the fair value hierarchy. The Company estimated that if the assets were purchased at their carrying value, they would yield a return to the purchaser that is in line with current market participant expectations.

During 2025, the Company recorded a net investment in lease of $6.6 billion (US$4.8 billion) associated with the Southeast Gateway pipeline lease commencement, with no selling profit or losses recorded upon derecognition of the underlying asset. The Company recorded an expected credit loss provision of $113 million in Plant operating costs and other, relating to the initial net investment in lease balance.

Future lease payments to be received under the existing sales-type leases are as follows:

at December 31 (millions of Canadian $)	2025	2024
Less than one year	**1,256**	333
One to two years	**1,000**	333
Two to three years	**1,000**	333
Three to four years	**1,000**	333
Four to five years	**1,000**	333
More than five years	**24,508**	8,499
	29,764	10,164

The following table lists the components of the aggregate net investment in leases reflected on the Company's Consolidated balance sheet:

at December 31 (millions of Canadian $)	2025	2024
Net Investment in Leases		
Minimum lease payments	**29,764**	10,164
Unearned lease income	**(20,397)**	(7,323)
Lease receivable	**9,367**	2,841
Expected credit loss provision[1]	**(141)**	(59)
Present value of unguaranteed residual value	**140**	28
	9,366	2,810
Current portion included in Other current assets (Note 7)	**(1,256)**	(333)
	8,110	2,477

1 Includes $2 million gain (2024 – $6 million loss) on foreign currency translation.

For the year ended December 31, 2025, the Company recorded $787 million (2024 – $308 million; 2023 - $279 million) of sales-type lease income.

For the year ended December 31, 2025, the Company recorded an $84 million ECL expense (2024 – $23 million recovery; 2023 – $73 million recovery) relating to net investment in leases in Plant operating costs and other. Refer to Note 27, Risk management and financial instruments, for additional information.

10. EQUITY INVESTMENTS

		Income (Loss) from Equity Investments			Equity Investments	
	Ownership Interest at	year ended December 31			at December 31	
(millions of Canadian $)	December 31, 2025	2025	2024	2023	2025	2024
Canadian Natural Gas Pipelines						
TQM[1]	50%	**17**	17	17	**158**	160
Coastal GasLink[1]	35%	**95**	17	203	**896**	1,006
U.S. Natural Gas Pipelines						
Northern Border	50%	**145**	130	101	**766**	647
Millennium	47.5%	**70**	95	109	**(22)**	(21)
Iroquois	50%	**70**	100	98	**216**	221
Other	Various	**16**	16	16	**137**	135
Mexico Natural Gas Pipelines						
Sur de Texas	60%	**94**	283	78	**1,427**	1,403
Power and Energy Solutions						
Bruce Power[1]	48.3%	**767**	900	690	**7,780**	7,043
Other	Various	**—**	—	(2)	**—**	42
		1,274	1,558	1,310	**11,358**	10,636

1 Classified as a VIE. Refer to Note 31, Variable interest entities, for additional information.

Distributions and Contributions

Distributions received from equity investments and contributions made to equity investments for the years ended December 31, 2025, 2024 and 2023 were as follows:

year ended December 31 (millions of Canadian $)	2025	2024	2023
Distributions			
Distributions received from operating activities of equity investments	**1,616**	1,607	1,158
Coastal GasLink LP subordinated loan repayment[1,2]	**—**	3,147	—
Other[1]	**5**	539	23
	1,621	5,293	1,181
Contributions[1]			
Contributions made to other equity investments	**986**	719	918
Contributions to Coastal GasLink LP[2]	**65**	3,964	3,231
	1,051	4,683	4,149

1 Included in Investing activities in the Consolidated statement of cash flows.

2 In December 2024, TC Energy made an equity contribution of $3,137 million to Coastal GasLink LP, which used the funds to repay the balance owing to TC Energy under the subordinated loan agreement. The contribution and repayment were included in Investing activities in the Consolidated statement of cash flows. Refer to Note 11, Loans with affiliates, for additional information.

Coastal GasLink Pipeline Limited Partnership

In November 2024, Coastal GasLink Pipeline Limited Partnership (Coastal GasLink LP) executed a commercial agreement with LNG Canada (LNGC) and each of the five LNGC participants (LNGC Participants) that declared commercial in-service for the Coastal GasLink pipeline, enabling toll collection from customers retroactive to October 1, 2024. The agreement also provided for a one-time payment of $199 million from LNGC Participants to TC Energy in recognition of completed work and final cost settlement, payable upon the earlier of three months following the LNG facility's declared in-service date or December 15, 2025.

Effective July 12, 2025, the LNG facility was declared in-service by LNGC. Pursuant to the commercial agreement, TC Energy received the one-time payment of $199 million, settled through a cash distribution in October 2025. This payment, which accrues entirely to TC Energy under the contractual arrangements between the Coastal GasLink LP partners, was recognized as an in-substance distribution from Coastal GasLink LP and reflected in Accounts receivable and Equity investments on the Company's Consolidated balance sheet as at December 31, 2024.

The Coastal GasLink project reached mechanical completion in November 2023 and was ready to deliver commissioning gas to the LNGC facility by the end of 2023. These milestones entitled Coastal GasLink LP to receive a $200 million incentive payment from LNGC, which was recorded as Accounts receivable on the Consolidated balance sheet and Income (loss) from equity investments in the Consolidated statement of income as at and for the year ended December 31, 2023. The incentive payment was settled through a cash distribution in February 2024.

In February 2023, Coastal GasLink LP announced an increase in the revised capital cost of the Coastal GasLink pipeline. The increase in project costs and the expectation that additional equity contributions under the subordinated loan agreement would be predominantly funded by TC Energy was an indication of significant adverse impact on the estimated fair value of the Company’s investment in Coastal GasLink LP. The Company completed valuation assessments and concluded that the fair value of its investment in Coastal GasLink LP was below its carrying value, which resulted in a pre-tax impairment charge of $2,100 million in 2023 and cumulative impairment charges of $5,148 million, or $4,586 million after tax, between December 31, 2022 and September 30, 2023. No further indication of other-than-temporary impairments of the Company's investment in Coastal GasLink LP have since been identified and no further impairment charges have been recorded.

At December 31, 2025, the carrying value of the Company's investment in Coastal GasLink LP was $896 million (2024 – $1,006 million).

Summarized Financial Information of Equity Investments

year ended December 31 (millions of Canadian $)	2025	2024	2023
Income			
Revenues	**7,493**	6,962	6,197
Operating and other expenses	**(4,412)**	(3,783)	(3,343)
Net income	**2,405**	3,026	2,457
Net income attributable to TC Energy	**1,274**	1,558	1,310

at December 31 (millions of Canadian $)	2025	2024
Balance Sheet		
Current assets	**3,438**	3,959
Non-current assets	**47,233**	44,835
Current liabilities	**(1,888)**	(2,111)
Non-current liabilities	**(22,389)**	(21,729)

At December 31, 2025, the cumulative carrying value of the Company's equity investments was $834 million (2024 – $769 million) lower than the cumulative underlying equity in the net assets primarily due to the impairment of the equity investment in Coastal GasLink LP, partially offset by fair value adjustments at the time of acquisition or partial disposition, as well as interest capitalized during construction.

11. LOANS WITH AFFILIATES

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

Coastal GasLink Pipeline Limited Partnership

TC Energy holds a 35 per cent equity interest in Coastal GasLink LP and operates the Coastal GasLink pipeline.

Subordinated Loan Agreement

TC Energy has a subordinated loan agreement with Coastal GasLink LP under which the Company advances non-revolving loans at floating market-based interest rates to Coastal GasLink LP to fund capital costs associated with the Coastal GasLink Pipeline project.

Coastal GasLink LP partners, including TC Energy, are contractually obligated to contribute equity to Coastal GasLink LP to ultimately fund the settlement of amounts outstanding under the subordinated loan agreement, with an expectation that such equity will predominantly be contributed by TC Energy. Because of this expectation, amounts drawn under the subordinated loan agreement have been accounted for as in-substance equity contributions, presented as Contributions to equity investments in the Company's Consolidated statement of cash flows. Repayments of amounts owed by Coastal GasLink LP to the Company have been accounted for as in-substance equity distributions, presented in Other distributions from equity investments in the Company's Consolidated statement of cash flows.

On December 17, 2024, following the declared commercial in-service of the pipeline, Coastal GasLink LP repaid the $3,147 million balance owing to TC Energy under the subordinated loan agreement. The Company's share of equity contributions required to fund Coastal GasLink LP's repayment of the outstanding loan balance amounted to $3,137 million. Unused committed capacity available for use by Coastal GasLink LP at December 31, 2025 was $163 million (December 31, 2024 – $228 million).

Subordinated Demand Revolving Credit Facility Agreement

The Company has a subordinated demand revolving credit facility agreement with Coastal GasLink LP to provide additional short-term liquidity and funding flexibility to projects under construction. Facilities available through this agreement bear interest at floating market-based rates and have a combined capacity of $120 million at December 31, 2025 and 2024 with no outstanding balances at December 31, 2025 and 2024.

Sur de Texas

TC Energy holds a 60 per cent equity interest in a joint venture with IEnova Infraestructura Marina Holding B.V. (IEnova) to own the Sur de Texas pipeline, operated by TC Energy. On December 15, 2025, TC Energía Mexicana, S. de R.L. de C.V. (TCEM) entered into a subordinated demand revolving credit facility to borrow funds from the joint venture at a floating interest rate. The facility has a capacity of US$270 million, maturing in December 2028. At December 31, 2025, the unused capacity available for use by TCEM was $259 million (US$189 million) and the outstanding balance of the loan was $111 million (US$81 million), which is presented in Other long-term liabilities on the Company's Consolidated balance sheet.

12. RATE-REGULATED BUSINESSES

TC Energy's businesses that apply RRA currently include almost all of the Canadian, U.S. and Mexico natural gas pipelines and certain U.S. natural gas storage operations. Rate-regulated businesses account for and report assets and liabilities consistent with the resulting economic impact of the established rates, provided the rates are designed to recover the costs of providing the service and the competitive environment makes it probable that such rates can be charged and collected. Certain revenues and expenses subject to utility regulation or rate determination that would otherwise be reflected in the statement of income are deferred on the balance sheet and are expected to be recovered from or refunded to customers in future service rates.

Canadian Regulated Operations

The majority of TC Energy's Canadian natural gas pipelines are regulated by the CER under the Canadian Energy Regulator Act. The CER regulates the construction and operation of facilities and the terms and conditions of services, including rates, for the Company's Canadian regulated natural gas transmission systems under federal jurisdiction. The Impact Assessment Agency of Canada continues to assess designated projects.

TC Energy's Canadian natural gas transmission services are supplied under natural gas transportation tariffs that provide for cost recovery, including return of and on capital as approved by the CER. Subject to the terms of any settlement, rates charged for these services are typically set through a process that involves filing an application with the regulator wherein forecasted operating costs, including a return of and on capital, determine the revenue requirement for the upcoming year or multiple years. To the extent actual costs and revenues are more or less than forecasted costs and revenues, the regulator generally allows the difference to be deferred to a future period and recovered or refunded in rates at that time. Differences between actual and forecasted costs that the regulator does not allow to be deferred are included in the determination of net income in the year they occur. The Company's most significant regulated Canadian natural gas pipelines, based on total operated pipe length, are described below.

NGTL System

The NGTL System currently operates under the terms of the 2025-2029 Revenue Requirement Settlement, which was approved by the CER in September 2024 (the 2025-2029 NGTL Settlement). The 2025-2029 NGTL Settlement enables an investment framework that supports the approval by the Company's Board of Directors (Board) to allocate up to $3.3 billion of capital towards progression of the Multi-Year Growth Plan for expansion facilities to meet commitments on the NGTL System. It is comprised of multiple distinct projects with various targeted in-service dates, beginning in 2026, subject to final Company and regulatory approvals.

The 2025-2029 NGTL Settlement maintains an ROE of 10.1 per cent on 40 per cent deemed common equity while increasing NGTL System depreciation rates, with an incentive that allows the NGTL System the opportunity to further increase depreciation rates if tolls fall below specified levels or if growth projects are undertaken. The 2025-2029 NGTL Settlement introduces a new incentive mechanism to reduce both physical emissions and emission compliance costs, which builds on the incentive mechanism for certain operating costs where variances from projected amounts and emissions savings are shared with customers. A provision for review exists in the 2025-2029 NGTL Settlement if tolls exceed a pre-determined level or if final Company approvals of the multi-year growth plan are not obtained.

NGTL System's 2023 and 2024 results reflected the terms of the 2020-2024 Revenue Requirement Settlement which included an approved ROE of 10.1 per cent on 40 per cent deemed common equity, provided the NGTL System the opportunity to increase depreciation rates if tolls fell below specified levels and provided an incentive mechanism for certain operating costs where variances from projected amounts were shared with its customers.

Canadian Mainline

In April 2020, the CER approved the six-year unanimous negotiated settlement (the 2021-2026 Mainline Settlement) effective January 1, 2021. Similar to the previous settlement, the 2021-2026 Mainline Settlement maintains a base equity return of 10.1 per cent on 40 per cent deemed common equity and includes an incentive to either achieve cost efficiencies and/or increase revenues on the pipeline with a beneficial sharing mechanism to both customers and TC Energy.

Toll stabilization is achieved using deferral accounts, including the toll-stabilization account and the short-term adjustment accounts (STAA), which capture the surplus or shortfall between system revenues and cost of service each year under the 2021-2026 Mainline Settlement. A portion of the STAA commenced amortization in 2023 and the remainder commenced amortization in 2024, according to the terms outlined in the 2021-2026 Mainline Settlement as predetermined thresholds per the settlement agreement were met.

U.S. Regulated Operations

TC Energy's U.S. regulated natural gas pipelines operate under the provisions of the Natural Gas Act of 1938 (NGA), the Natural Gas Policy Act of 1978 and the Energy Policy Act of 2005, and are subject to the jurisdiction of FERC. The NGA grants FERC authority over the construction, acquisition and operation of pipelines and related facilities, including the regulation of tariffs which incorporates maximum and minimum rates for services and allows U.S. regulated natural gas pipelines to discount or negotiate rates on a non-discriminatory basis. The Company's most significant regulated U.S. natural gas pipelines, based on effective ownership and total operated pipe length, are described below.

Columbia Gas

Columbia Gas' natural gas transportation and storage services are provided under a tariff at rates subject to FERC approval. Columbia Gas operates under a settlement approved by FERC in October 2025 (the 2025 Columbia Gas Settlement). As part of the settlement, there is a moratorium on any further rate changes until April 1, 2028, and Columbia Gas must file for new rates with an effective date no later than April 1, 2031. The settlement also included additional rate step ups in April 2026 and April 2027 to reflect anticipated modernization-related spend.

ANR Pipeline

ANR Pipeline operates under rates established through a 2022 FERC-approved rate settlement (the 2022 ANR Settlement). In 2023, previously accrued rate refund liabilities, including interest, were refunded to customers. The 2022 ANR Settlement included a moratorium on rate changes until November 1, 2025, and required ANR to file for new rates with an effective date no later than August 1, 2028. The settlement also provided for a rate step up effective August 2024 related to certain modernization projects and an additional rate step up effective no later than August 1, 2028. In April 2025, ANR filed a Section 4 Rate Case with FERC requesting an increase to maximum transportation rates effective November 1, 2025, subject to refund. As of December 31, 2025, ANR is pursuing a collaborative process to find a mutually beneficial outcome with customers.

Columbia Gulf

Columbia Gulf operates under a settlement approved by FERC in August 2023, effective March 1, 2024 (the 2023 Columbia Gulf Settlement). The 2023 Columbia Gulf Settlement includes a moratorium on further rate changes through February 28, 2027, and Columbia Gulf must file for new rates no later than March 1, 2029.

Great Lakes

Great Lakes operates under a rate settlement approved by FERC in April 2022 (the 2022 Great Lakes Settlement), which maintains Great Lakes' existing maximum transportation rates through October 31, 2025. The 2022 Great Lakes Settlement contained a moratorium until October 31, 2025. In April 2025, Great Lakes filed a Section 4 Rate Case with FERC requesting an increase to maximum transportation rates effective November 1, 2025, subject to refund. As of December 31, 2025, Great Lakes is pursuing a collaborative process to find a mutually beneficial outcome with customers.

Tuscarora

Tuscarora operates under rates established as part of the FERC-approved rate settlement in September 2023 (the 2023 Tuscarora Settlement). The 2023 Tuscarora Settlement provided for phased rate reductions as of February 1, 2023, and additionally as of February 1, 2025. The 2023 Tuscarora Settlement contains a moratorium that expires December 1, 2028. Tuscarora is required to file new rates by December 1, 2028.

Gas Transmission Northwest

Gas Transmission Northwest (GTN) operates under rates established as part of the FERC-approved rate settlement in October 2024 (the 2024 GTN Settlement). The 2024 GTN Settlement maintains the currently effective rates (the pre-filed rates) from April 1, 2024, through March 31, 2026. GTN will then reduce its pre-filed rates starting on April 1, 2026, through March 31, 2027. The 2024 GTN Settlement contains a moratorium that expires March 31, 2027. GTN is required to file new rates by April 1, 2027.

Mexico Regulated Operations

TC Energy's natural gas pipelines in Mexico are regulated by the CNE. While the majority of the Company's capacity is subscribed under a long-term contractual rate, the CNE sets rates for interruptible services. The rates in effect on TC Energy's Mexico natural gas pipelines provide for cost recovery, including a return of and on invested capital.

Regulatory Assets and Liabilities

at December 31 (millions of Canadian $)	Remaining Recovery/ Settlement Period (years)	2025	2024
Regulatory Assets			
Deferred income taxes[1]	n/a	**2,760**	2,593
Operating and debt-service regulatory assets[2]	1	**—**	56
Foreign exchange on long-term debt[1,3]	1-4	**23**	39
Other	n/a	**188**	117
		2,971	2,805
Less: Current portion included in Other current assets (Note 7)		**58**	123
		2,913	2,682
Regulatory Liabilities			
Pipeline abandonment trust balances[4]	n/a	**3,143**	2,686
Deferred income taxes – U.S. Tax Reform[5]	n/a	**1,098**	1,197
Canadian Mainline short-term adjustment and toll-stabilization accounts[6,7]	n/a	**705**	553
Cost of removal[8]	n/a	**407**	376
Canadian Mainline bridging amortization account[6]	5	**268**	322
Pensions and other post-retirement benefits[9]	n/a	**266**	122
Deferred income taxes[1]	n/a	**195**	188
Operating and debt-service regulatory liabilities[2]	1	**134**	50
ANR post-employment and retirement benefits other than pension[10]	n/a	**43**	45
Canadian Mainline long-term adjustment account[6,11]	1	**37**	74
Other	n/a	**77**	43
		6,373	5,656
Less: Current portion included in Accounts payable and other (Note 16)		**532**	353
		5,841	5,303

1 These regulatory assets and liabilities are underpinned by non-cash transactions or are recovered without an allowance for return as approved by the regulator. Accordingly, these regulatory assets or liabilities are not included in rate base and do not yield a return on investment during the recovery period.

2 Operating and debt-service regulatory assets and liabilities represent the accumulation of cost and revenue variances to be included in determination of rates in the following year.

3 Foreign exchange on long-term debt of the NGTL System represents the variance resulting from revaluing foreign currency-denominated debt instruments to the current foreign exchange rate from the historical foreign exchange rate at the time of issue. Foreign exchange gains and losses realized when foreign debt matures or is redeemed early are expected to be recovered or refunded through the determination of future tolls.

4 This balance represents the amounts collected in tolls from customers and is included in the LMCI restricted investments to fund future abandonment of the Company's CER-regulated pipeline facilities.

5 The U.S. corporate income tax rate was reduced from 35 per cent to 21 per cent in 2017 as a result of H.R.1, the Tax Cuts and Jobs Act (U.S. Tax Reform). This U.S. regulated operations balance, where applicable, represents established regulatory liabilities driven by 2018 FERC prescribed changes related to U.S. Tax Reform being amortized over varying terms that approximate the expected reversal of the underlying deferred tax liabilities that gave rise to the regulatory liabilities.

6 These regulatory accounts are used to capture revenue and cost variances plus toll-stabilization adjustments during the 2015-2030 settlement term.

7 Under the terms of the 2021-2026 Mainline Settlement, a portion of the STAA account commenced amortization in 2023 and the remainder commenced amortization in 2024, as predetermined thresholds were met, over the terms outlined per the settlement agreement.

8 This balance represents anticipated costs of removal that have been, and continue to be, included in depreciation rates and collected in the service rates of certain rate-regulated operations for future costs to be incurred.

9 These balances represent the regulatory offset to pension plan and other post-retirement benefit obligations to the extent the amounts are expected to be collected from or refunded to customers in future rates.

10 This balance represents the amount ANR estimates it would be required to refund to its customers for post-retirement and post-employment benefit amounts collected through its FERC-approved rates that have not been used to pay benefits to its employees. Pursuant to a FERC-approved rate settlement, the $43 million (US$32 million) balance at December 31, 2025 is subject to resolution through future regulatory proceedings and, accordingly, a settlement period cannot be determined at this time.

11 Under the terms of the 2021-2026 Mainline Settlement, $223 million is amortized over the six-year settlement term.

13. GOODWILL

The Company's Goodwill balance on the Consolidated balance sheet is comprised of the following amounts:

at December 31	2025		2024	
(millions)	Canadian dollars	U.S. dollars[1]	Canadian dollars	U.S. dollars[1]
Columbia	**10,082**	**7,351**	10,588	7,351
ANR	**2,669**	**1,946**	2,803	1,946
Great Lakes	**167**	**122**	176	122
North Baja	**66**	**48**	70	48
Tuscarora	**32**	**23**	33	23
	13,016	**9,490**	13,670	9,490

1 Represents gross amounts of goodwill as at December 31, 2025 and 2024 of US$10,828 million, net of accumulated impairment of US$1,338 million.

Changes in Goodwill were as follows:

(millions of Canadian $)	U.S. Natural Gas Pipelines
Balance at January 1, 2024	12,532
Foreign exchange rate changes	1,138
Balance at December 31, 2024	13,670
Foreign exchange rate changes	**(654)**
Balance at December 31, 2025	**13,016**

As part of the annual goodwill impairment assessment at December 31, 2025, the Company evaluated qualitative factors impacting the fair value of the underlying reporting units for all reporting units other than the Columbia reporting unit. It was determined that it was more likely than not that the fair value of all reporting units exceeded their carrying amounts, including goodwill.

Columbia

The Company elected to proceed directly to a quantitative annual impairment test at December 31, 2025 for the $10,082 million (US$7,351 million) of goodwill related to the Columbia reporting unit subsequent to the 2025 Columbia Gas Settlement. To determine fair value, the Company used a discounted cash flow model incorporating projections of future cash flows as well as a valuation multiple and applied a risk-adjusted discount rate which involved significant estimates and judgments. The fair value measurement is classified as Level III in the fair value hierarchy. It was determined that the fair value of the Columbia reporting unit exceeded its carrying value, including goodwill, at December 31, 2025.

Great Lakes

The estimated fair value of the Great Lakes reporting unit in excess of its carrying value was less than 10 per cent at the date of the last quantitative goodwill impairment test in 2022. Any future reductions in cash flow forecasts or adverse changes in other key assumptions could result in a future impairment of the goodwill balance.

14. OTHER LONG-TERM ASSETS

at December 31 (millions of Canadian $)	**2025**	**2024**
Employee post-retirement benefits (Note 26)	**967**	758
Contract assets (Note 6)	**627**	608
Deferred income tax assets (Note 18)	**356**	428
Fair value of derivative instruments (Note 27)	**161**	122
Capital projects in development	**81**	164
Other	**290**	330
	2,482	2,410

15. NOTES PAYABLE

at December 31	2025		2024	
(millions of Canadian $, unless otherwise noted)	**Outstanding**	**Weighted Average Interest Rate per Annum**	**Outstanding**	**Weighted Average Interest Rate per Annum**
Canada[1]	**584**	**3.9%**	308	4.7%
U.S. (2025 – US$449; 2024 – US$55)	**616**	**4.1%**	79	4.7%
	1,200		387	

1 At December 31, 2025, Notes payable consisted of Canadian dollar-denominated notes of $68 million (2024 – nil) and U.S. dollar-denominated notes of US$348 million (2024 – US$214 million).

At December 31, 2025, Notes payable reflects short-term borrowings in Canada by TCPL and in the U.S. by TransCanada PipeLine USA Ltd. (TCPL USA) and Columbia Pipelines Holdings Company LLC (CPHC). At December 31, 2024, there were no amounts outstanding at CPHC.

At December 31, 2025, total committed revolving and demand credit facilities were $11.9 billion (2024 – $12.2 billion). When drawn, interest on these lines of credit is charged at negotiated floating rates of Canadian and U.S. banks, and at other negotiated financial bases. These unsecured credit facilities included the following:

at December 31 (billions of Canadian $, unless otherwise noted)			2025		2024
Borrowers	**Description**	**Matures**	**Total Facilities**	**Unused Capacity[1]**	**Total Facilities**
Committed, syndicated, revolving, extendible, senior unsecured credit facilities[2]:					
TCPL	Supports commercial paper program and for general corporate purposes	December 2030	**3.0**	**2.9**	3.0
TCPL / TCPL USA	Supports commercial paper programs and for general corporate purposes of the borrowers, guaranteed by TCPL	December 2026	**US 1.0**	**US 0.8**	US 1.0
TCPL / TCPL USA	Supports commercial paper programs and for general corporate purposes of the borrowers, guaranteed by TCPL	December 2028	**US 2.5**	**US 2.3**	US 2.5
Columbia Pipelines Holding Company LLC[3]	Supports commercial paper program and general corporate purposes of the borrower	December 2028	**US 1.5**	**US 1.1**	US 1.5
Demand senior unsecured revolving credit facilities[2]:					
TCPL / TCPL USA	Supports the issuance of letters of credit and provides additional liquidity; TCPL USA facility guaranteed by TCPL	Demand	**2.0** [4]	**1.3**	2.0 [4]

1 Unused capacity is net of commercial paper outstanding and facility draws.

2 Provisions of various trust indentures and credit arrangements with the Company's subsidiaries can restrict their ability to declare and pay dividends or make distributions under certain circumstances. If such restrictions apply, they may, in turn, have an impact on the Company's ability to declare and pay dividends on common and preferred shares. These trust indentures and credit arrangements also require the Company to comply with various affirmative and negative covenants and maintain certain financial ratios. At December 31, 2025, the Company was in compliance with all financial covenants.

3 Columbia Pipelines Holding Company LLC is a partially-owned subsidiary of TC Energy with 40 per cent non-controlling interest.

4 Or the U.S. dollar equivalent.

For the year ended December 31, 2025, the cost to maintain the above facilities was $15 million (2024 – $18 million; 2023 – $16 million).

16. ACCOUNTS PAYABLE AND OTHER

at December 31 (millions of Canadian $)	**2025**	**2024**
Trade payables	**3,263**	3,699
Regulatory liabilities (Note 12)	**532**	353
Fair value of derivative instruments (Note 27)	**380**	507
Factoring arrangement (Note 9)	**351**	—
Gas transportation and exchange payable	**158**	118
Emissions expense payable	**91**	101
Operating lease liabilities (Note 9)	**61**	60
Contract liabilities (Note 6)	**46**	30
Income tax liabilities	**38**	143
Other	**354**	286
	5,274	5,297

17. OTHER LONG-TERM LIABILITIES

at December 31 (millions of Canadian $)	**2025**	**2024**
Operating lease liabilities (Note 9)	**370**	451
Fair value of derivative instruments (Note 27)	**149**	209
Asset retirement obligations	**119**	108
Loan from affiliate (Note 11)	**111**	—
Employee post-retirement benefits (Note 26)	**69**	94
Other	**216**	189
	1,034	1,051

18. INCOME TAXES

Geographic Components of Income before Income Taxes

year ended December 31 (millions of Canadian $)	2025	2024	2023
Canada	**1,959**	1,469	(194)
Foreign	**3,485**	4,437	3,492
Income before Income Taxes	**5,444**	5,906	3,298

Provision for Income Taxes

year ended December 31 (millions of Canadian $)	2025	2024	2023
Current			
Canada - federal	**54**	90	34
Canada - provincial	**5**	71	40
Foreign	**308**	334	790
	367	495	864
Deferred			
Canada - federal	**213**	80	3
Canada - provincial	**139**	56	3
Foreign	**419**	291	(28)
	771	427	(22)
Income Tax Expense	**1,138**	922	842

Reconciliation of Income Tax Expense

year ended December 31	2025		2024		2023	
(millions of Canadian $, unless otherwise noted)	Amount	Percentage	Amount	Percentage	Amount	Percentage
Income before income taxes	**5,444**		5,906		3,298	
Canadian federal statutory income tax rate	**15%**		15%		15%	
Expected income tax expense	**817**		886		495	
Canadian federal reconciling items						
Income tax differential related to regulated operations	**(24)**	**(0.4%)**	(68)	(1.2%)	(108)	(3.3%)
Non-taxable capital (gain) loss	**(20)**	**(0.4%)**	12	0.2%	113	3.4%
Changes in valuation allowances	**—**	**—**	3	0.1%	114	3.5%
Effect of cross-border taxes	**(25)**	**(0.5%)**	(23)	(0.4%)	(27)	(0.8%)
Canadian provincial taxes[1]	**143**	**2.6%**	103	1.7%	22	0.7%
Foreign reconciling items						
United States						
Rate differential	**177**	**3.3%**	168	2.8%	136	4.1%
State and local income taxes, net of federal effect	**(28)**	**(0.5%)**	123	2.1%	76	2.3%
Income from non-controlling interests	**(125)**	**(2.3%)**	(121)	(2.0%)	(31)	(0.9%)
Other	**(16)**	**(0.3%)**	(12)	(0.2%)	(8)	(0.2%)
Mexico						
Mexico foreign exchange exposure	**213**	**3.9%**	(246)	(4.2%)	163	4.9%
Rate differential	**57**	**1.0%**	234	4.0%	94	2.9%
Income from equity investments	**(28)**	**(0.5%)**	(84)	(1.4%)	(23)	(0.7%)
Income tax differential related to regulated operations	**(45)**	**(0.8%)**	(109)	(1.8%)	(79)	(2.4%)
Withholding tax	**41**	**0.8%**	35	0.6%	12	0.4%
Other	**8**	**0.1%**	2	—	2	0.1%
Other foreign jurisdictions	**(2)**	**—**	3	0.1%	(91)	(2.8%)
Other adjustments	**(5)**	**(0.1%)**	16	0.3%	(18)	(0.5%)
Income Tax Expense	**1,138**	**20.9%**	922	15.7%	842	25.7%

1 Ontario provincial tax comprises the majority of Canada provincial taxes.

Deferred Income Tax Assets and Liabilities

at December 31 (millions of Canadian $)	2025	2024
Deferred Income Tax Assets		
Tax loss and credit carryforwards	**1,728**	1,987
Disallowed interest carryforward	**100**	115
Regulatory and other deferred amounts	**644**	612
Unrealized foreign exchange losses on long-term debt	**290**	467
Other	**57**	143
	2,819	3,324
Less: Valuation allowance	**789**	931
	2,030	2,393
Deferred Income Tax Liabilities		
Difference in accounting and tax bases of plant, property and equipment	**6,792**	6,488
Equity investments	**1,478**	1,280
Taxes on future revenue requirement	**654**	612
Financial instruments	**176**	168
Other	**251**	301
	9,351	8,849
Net Deferred Income Tax Liabilities	**7,321**	6,456

The above deferred tax amounts have been classified on the Consolidated balance sheet as follows:

at December 31 (millions of Canadian $)	2025	2024
Deferred Income Tax Assets		
Other long-term assets (Note 14)	**356**	428
Deferred Income Tax Liabilities		
Deferred income tax liabilities	**7,677**	6,884
Net Deferred Income Tax Liabilities	**7,321**	6,456

The following table provides details of the tax loss and credit carryforwards and valuation allowances:

at December 31, 2025 (millions of Canadian $)	Unused Amounts	Deferred Tax Asset	Valuation Allowance	Expiry Years
Tax Loss and Credit Carryforwards				
Operating losses	**5,838**	**1,302**	**—**	**2026-2045**
Foreign federal and state operating losses	**1,746**	**173**	**41**	**2026-2037**
Capital loss	**618**	**74**	**74**	**Indefinite**
Minimum tax	**—**	**179**	**42**	**2033-Indefinite**
		1,728	**157**	
Restricted Interest and Financing Expense	**424**	**100**	**—**	**Indefinite**
Unrealized Foreign Exchange on Long-Term Debt	**—**	**290**	**290**	
Equity Investments	**—**	**342**	**342**	
			789	

TC Energy recorded a decrease in valuation allowance in the year primarily resulting from unrealized foreign exchange movements.

Unremitted Earnings of Foreign Investments

Income taxes have not been provided on the unremitted earnings of foreign investments that the Company does not intend to repatriate in the foreseeable future. Deferred income tax liabilities would have increased at December 31, 2025 by approximately $2,198 million (2024 – $1,728 million) if there had been a provision for these taxes.

Income Tax Payments (Refunds)

at December 31 (millions of Canadian $)	2025	2024	2023
Jurisdiction			
Canada - federal	**73**	53	61
Canada - provincial	**17**	6	(1)
United States	**368**	302	692
Mexico	**84**	34	26
Other - foreign	**1**	(8)	13
	543	387	791

Reconciliation of Unrecognized Tax Benefit

Below is the reconciliation of the annual changes in the total unrecognized tax benefit:

at December 31 (millions of Canadian $)	2025	2024	2023
Unrecognized tax benefit at beginning of year	**72**	85	91
Gross increase - tax positions in prior years	**2**	3	9
Gross decrease - tax positions in prior years	**(4)**	(2)	(1)
Gross increase - tax positions in current year	**18**	5	16
Gross decrease - tax positions in current year	**—**	(2)	—
Settlement	**—**	(13)	—
Lapse of statutes of limitations	**(5)**	(4)	(30)
Unrecognized Tax Benefit at End of Year	**83**	72	85

TC Energy's practice is to recognize interest and penalties related to income tax uncertainties in Income tax expense. Income tax expense for the year ended December 31, 2025 reflects $7 million interest expense (2024 – $1 million recovery; 2023 – $3 million expense). At December 31, 2025, the Company accrued $26 million in interest expense (2024 – $19 million; 2023 – $20 million). The Company incurred no penalties associated with income tax uncertainties related to income tax expense for the years ended December 31, 2025, 2024 and 2023 and no penalties were accrued as at December 31, 2025, 2024 and 2023.

The Company has substantially concluded all Canadian federal and provincial income tax matters for the years through 2017. Substantially all material U.S. federal, state and local income tax matters have been concluded for years through 2019. Substantially all material Mexico income tax matters have been concluded for years through 2019.

19. LONG-TERM DEBT

at December 31		2025		2024	
(millions of Canadian $, unless otherwise noted)	Maturity Dates	Outstanding	Interest Rate[1]	Outstanding	Interest Rate[1]
TRANSCANADA PIPELINES LIMITED					
Medium Term Notes					
Canadian	2026 to 2055	**14,241**	**4.8%**	13,141	4.7%
Senior Unsecured Notes					
U.S. (2025 – US$10,850 and 2024 – US$11,792)	2028 to 2049	**14,882**	**5.5%**	16,985	5.5%
		29,123		30,126	
NOVA GAS TRANSMISSION LTD.					
Medium Term Notes					
Canadian	2026 to 2030	**417**	**7.1%**	504	7.4%
U.S. (2025 and 2024 – US$33)	2026	**45**	**7.5%**	47	7.5%
		462		551	
COLUMBIA PIPELINES OPERATING COMPANY LLC					
Senior Unsecured Notes					
U.S. (2025 and 2024 – US$6,500)	2030 to 2063	**8,915**	**6.2%**	9,362	6.0%
COLUMBIA PIPELINES HOLDING COMPANY LLC					
Senior Unsecured Notes					
U.S. (2025 – US$2,650; 2024 – US$1,900)	2026 to 2034	**3,634**	**5.7%**	2,737	5.9%
ANR PIPELINE COMPANY					
Senior Unsecured Notes					
U.S. (2025 – US$1,640; 2024 – US$1,047)	2026 to 2037	**2,249**	**4.3%**	1,509	3.7%
TC PIPELINES, LP					
Senior Unsecured Notes					
U.S. (2025 – US$500 and 2024 – US$850)	2027	**686**	**4.0%**	1,224	4.2%
GAS TRANSMISSION NORTHWEST LLC					
Senior Unsecured Notes					
U.S. (2025 and 2024 – US$375)	2030 to 2035	**514**	**4.4%**	540	4.4%
GREAT LAKES GAS TRANSMISSION LIMITED PARTNERSHIP					
Unsecured Term Loan					
U.S. (2025 – US$205; 2024 – nil)	2028	**281**	**5.0%**	—	—
Senior Unsecured Notes					
U.S. (2025 – US$83; 2024 – US$104)	2028 to 2030	**114**	**7.6%**	150	7.6%
		395		150	
TC ENERGÍA MEXICANA, S. DE R.L. DE C.V.					
Senior Unsecured Term Loan					
U.S. (2025 – US$693; 2024 – US$1,370)	2028	**950**	**6.3%**	1,973	7.2%
		46,928		48,172	
Current portion of long-term debt		**(1,545)**		(2,955)	
Unamortized debt discount and issue costs		**(251)**		(252)	
Fair value adjustments[2]		**115**		11	
		45,247		44,976	

1 Interest rates are the effective interest rates except for those pertaining to long-term debt issued for the Company's Canadian regulated natural gas operations, in which case the weighted average interest rate is presented as approved by the regulators. The effective interest rate is calculated by discounting the expected future interest payments, adjusted for loan fees, premiums and discounts. Weighted average and effective interest rates are stated as at the respective outstanding dates.

2 The fair value adjustments include $93 million (2024 – $109 million) related to the acquisition of Columbia Pipeline Group, Inc. These adjustments also include a decrease of $17 million (2024 – decrease of $139 million) related to hedged interest rate risk and an increase of $39 million (2024 - increase of $41 million) related to discontinued hedge interest rate risk. Refer to Note 27, Risk management and financial instruments, for additional information.

Long-Term Debt Issued

The Company issued long-term debt over the three years ended December 31, 2025 as follows:

(millions of Canadian $, unless otherwise noted)					
Company	**Issue Date**	**Type**	**Maturity Date**	**Amount**	**Interest Rate**
TRANSCANADA PIPELINES LIMITED					
	November 2025	Medium Term Notes	November 2055	850	5.13%
	February 2025	Medium Term Notes	February 2035	1,000	4.58%
	August 2024	Term Loan[1]	August 2024	US 1,242	Floating
	May 2023	Senior Unsecured Term Loan[2]	May 2026	US 1,024	Floating
	March 2023	Senior Unsecured Notes[3]	March 2026	US 850	6.20%
	March 2023	Senior Unsecured Notes[3]	March 2026	US 400	Floating
	March 2023	Medium Term Notes	July 2030	1,250	5.28%
	March 2023	Medium Term Notes[3]	March 2026	600	5.42%
	March 2023	Medium Term Notes[3]	March 2026	400	Floating
COLUMBIA PIPELINES HOLDING COMPANY LLC					
	November 2025	Senior Unsecured Notes	November 2032	US 750	5.00%
	September 2024	Senior Unsecured Notes	October 2031	US 400	5.10%
	January 2024	Senior Unsecured Notes	January 2034	US 500	5.68%
	August 2023	Senior Unsecured Notes	August 2028	US 700	6.04%
	August 2023	Senior Unsecured Notes	August 2026	US 300	6.06%
GREAT LAKES GAS TRANSMISSION LIMITED PARTNERSHIP					
	October 2025	Unsecured Term Loan	October 2028	US 205	Floating
ANR PIPELINE COMPANY					
	September 2025	Senior Unsecured Notes	September 2031	US 250	5.23%
	September 2025	Senior Unsecured Notes	September 2035	US 350	5.69%
COLUMBIA PIPELINES OPERATING COMPANY LLC					
	March 2025	Senior Unsecured Notes	February 2035	US 550	5.44%
	March 2025	Senior Unsecured Notes	February 2055	US 450	5.96%
	September 2024	Senior Unsecured Notes	October 2054	US 400	5.70%
	August 2023	Senior Unsecured Notes	November 2033	US 1,500	6.04%
	August 2023	Senior Unsecured Notes	November 2053	US 1,250	6.54%
	August 2023	Senior Unsecured Notes	August 2030	US 750	5.93%
	August 2023	Senior Unsecured Notes	August 2043	US 600	6.50%
	August 2023	Senior Unsecured Notes	August 2063	US 500	6.71%
GAS TRANSMISSION NORTHWEST LLC					
	June 2023	Senior Unsecured Notes	June 2030	US 50	4.92%
TC ENERGÍA MEXICANA, S. DE R.L. DE C.V.					
	January 2023	Senior Unsecured Term Loan	January 2028	US 1,800	Floating
	January 2023	Senior Unsecured Revolving Credit Facility	January 2028	US 500	Floating

1 In August 2024, TCPL entered into a term loan to facilitate the Spinoff Transaction and, in August 2024, the term loan was fully repaid and retired upon delivery of senior unsecured notes issued by 6297782 LLC. Refer to Note 4, Discontinued operations, for additional information.

2 Fully repaid and retired in September 2023.

3 In October 2024, callable notes were repaid and retired at par.

Long-Term Debt Retired/Repaid

The Company retired/repaid long-term debt over the three years ended December 31, 2025 as follows:

(millions of Canadian $, unless otherwise noted) Company	Retirement/ Repayment Date	Type	Amount	Interest Rate
TRANSCANADA PIPELINES LIMITED				
	November 2025	Senior Unsecured Notes	US 850	4.88%
	October 2025	Senior Unsecured Notes	US 92	7.06%
	July 2025	Medium Term Notes	750	3.30%
	October 2024	Senior Unsecured Notes	US 1,250	1.00%
	October 2024	Senior Unsecured Notes[1]	US 850	6.20%
	October 2024	Senior Unsecured Notes[2]	US 739	2.50%
	October 2024	Senior Unsecured Notes[2]	US 441	4.88%
	October 2024	Senior Unsecured Notes[1]	US 400	Floating
	October 2024	Senior Unsecured Notes[2]	US 313	4.75%
	October 2024	Senior Unsecured Notes[2]	US 201	5.00%
	October 2024	Senior Unsecured Notes[2]	US 180	5.10%
	October 2024	Medium Term Notes[1]	600	5.42%
	October 2024	Medium Term Notes[2]	575	4.18%
	October 2024	Medium Term Notes[1]	400	Floating
	August 2024	Term Loan[3]	US 1,242	Floating
	June 2024	Medium Term Notes	750	Floating
	October 2023	Senior Unsecured Notes	US 625	3.75%
	September 2023	Senior Unsecured Term Loan	US 1,024	Floating
	July 2023	Medium Term Notes	750	3.69%
ANR PIPELINE COMPANY				
	June 2025	Senior Unsecured Notes	US 7	7.00%
	February 2024	Senior Unsecured Notes	US 125	7.38%
NOVA GAS TRANSMISSION LTD.				
	May 2025	Medium Term Notes	87	8.90%
	March 2024	Debentures	100	9.90%
	April 2023	Debentures	US 200	7.88%
COLUMBIA PIPELINES OPERATING COMPANY LLC				
	March 2025	Senior Unsecured Notes	US 1,000	4.50%
TC PIPELINES, LP				
	March 2025	Senior Unsecured Notes	US 350	4.38%
TC ENERGÍA MEXICANA, S. DE R.L. DE C.V.				
	Various 2025	Senior Unsecured Term Loan	US 677	Floating
	Various 2024	Senior Unsecured Term Loan	US 430	Floating
	Various 2024	Senior Unsecured Revolving Credit Facility	US 185	Floating
	Various 2023	Senior Unsecured Revolving Credit Facility	US 315	Floating
TUSCARORA GAS TRANSMISSION COMPANY				
	November 2023	Unsecured Term Loan	US 32	Floating

1 In October 2024, callable notes were repaid and retired at par.
2 In October 2024, TCPL purchased and cancelled notes at a 7.73 per cent weighted average discount, as a settlement of cash tender offers.
3 In August 2024, TCPL entered into a term loan to facilitate the Spinoff Transaction and, in August 2024, the term loan was fully repaid and retired upon delivery of senior unsecured notes issued by 6297782 LLC. Refer to Note 4, Discontinued operations, for additional information.

On February 5, 2026, TCPL retired $241 million of medium term notes bearing interest at a fixed rate of 8.29 per cent.

In October 2024, TCPL commenced and completed its cash tender offers to purchase and cancel certain senior unsecured notes and medium term notes at a 7.73 per cent weighted average discount. In addition, the Company repaid and retired outstanding callable notes at par. These extinguishments of debt resulted in a pre-tax net gain of $228 million, primarily due to the fair value discount and recognition of unamortized debt issue costs related to these notes. The net gain on debt extinguishment was recorded in Interest expense in the Consolidated statement of income.

Principal Repayments

At December 31, 2025, principal repayments for the next five years on the Company's long-term debt are approximately as follows:

(millions of Canadian $)	2026	2027	2028	2029	2030
Principal repayments on long-term debt	1,545	3,122	5,196	1,309	4,573

Interest Expense

year ended December 31 (millions of Canadian $)	2025	2024	2023
Interest on long-term debt	**2,537**	2,800	2,562
Interest on junior subordinated notes	**678**	638	617
Interest on short-term debt	**95**	60	165
Capitalized interest	**(10)**	(191)	(187)
Amortization and other financial charges[1]	**107**	158	106
Gain on debt extinguishment	**—**	(228)	—
	3,407	3,237	3,263
Interest allocated to discontinued operations (Note 4)	**—**	(218)	(297)
	3,407	3,019	2,966

1 Amortization and other financial charges include amortization of transaction costs and debt discounts calculated using the effective interest method and gains and losses on derivatives used to manage the Company's exposure to changes in interest rates.

The Company made interest payments of $3,284 million in 2025 (2024 – $3,398 million; 2023 – $2,931 million) on long-term debt, junior subordinated notes and short-term debt, net of interest capitalized.

20. JUNIOR SUBORDINATED NOTES

at December 31		2025		2024	
(millions of Canadian $, unless otherwise noted)	Maturity Date	Outstanding	Effective Interest Rate[1]	Outstanding	Effective Interest Rate[1]
TRANSCANADA PIPELINES LIMITED					
US$750 issued 2015 at 5.88%[2,3,4]	—	**—**	**—**	1,080	7.5%
$1,000 issued 2025 at 5.20%[5]	2056	**1,000**	**5.3%**	—	—
US$750 issued 2025 at 7.00%[6]	2065	**1,028**	**7.2%**	—	—
US$1,000 issued 2007 at 6.35%[7]	2067	**1,372**	**6.0%**	1,440	6.2%
US$1,200 issued 2016 at 6.13%[3,4]	2076	**1,646**	**7.6%**	1,729	8.0%
US$1,500 issued 2017 at 5.55%[3,4]	2077	**2,057**	**6.7%**	2,161	7.2%
$1,500 issued 2017 at 4.90%[3,4]	2077	**1,500**	**5.6%**	1,500	6.8%
US$1,100 issued 2019 at 5.75%[3,4]	2079	**1,509**	**7.3%**	1,584	7.7%
$500 issued 2021 at 4.45%[3,8]	2081	**500**	**4.5%**	500	5.7%
US$800 issued 2022 at 5.85%[3,8]	2082	**1,097**	**7.1%**	1,152	7.3%
US$370 issued 2025 at 6.25%	2085	**508**	**6.6%**	—	—
		12,217		11,146	
Unamortized debt discount and issue costs		**(123)**		(98)	
		12,094		11,048	

1 The effective interest rate is calculated by discounting the expected future interest payments using the coupon rate and any estimated future rate resets, adjusted for issue costs and discounts.
2 In May 2025, TCPL exercised its option to fully repay and retire the US$750 million junior subordinated notes that had a maturity date of 2075.
3 The junior subordinated notes were issued to TransCanada Trust (the Trust), a financing trust subsidiary wholly-owned by TCPL. While the obligations of the Trust are fully and unconditionally guaranteed by TCPL on a subordinated basis, the Trust is not consolidated in TC Energy's financial statements since TCPL does not have a variable interest in the Trust and the only substantive assets of the Trust are junior subordinated notes of TCPL.
4 The coupon rate is initially a fixed interest rate for the first 10 years and converts to a floating rate thereafter.
5 The coupon rate is initially a fixed interest rate for the first five years and resets every five years thereafter, subject to a rate-reset minimum.
6 The coupon rate is initially a fixed interest rate for the first five years and resets every five years thereafter.
7 Junior subordinated notes of US$1.0 billion were issued in 2007 at a fixed rate of 6.35 per cent and converted in 2017 to bear interest at a floating rate.
8 The coupon rate is initially a fixed interest rate for the first 10 years and resets every five years thereafter.

Junior Subordinated Notes Issued

The Junior subordinated notes are subordinated in right of payment to existing and future senior indebtedness of TCPL.

In October 2025, TCPL issued US$370 million of junior subordinated notes maturing in 2085 with a fixed interest rate of 6.25 per cent. The junior subordinated notes are callable at TCPL's option at any time on or after November 1, 2030 at 100 per cent of the principal amount plus accrued and unpaid interest to the date of redemption.

In August 2025, TCPL issued $1.0 billion of junior subordinated notes maturing in 2056 with a fixed interest rate of 5.20 per cent per year until February 15, 2031. The rate on the junior subordinated notes will reset every five years commencing February 2031 until February 2056 to the then Five-Year Government of Canada Yield, as defined in the document governing the subordinated notes, plus 2.148 per cent per annum, subject to a rate-reset minimum. The junior subordinated notes are callable at TCPL's option at any time from November 15, 2030 to February 15, 2031 and on each interest payment and reset date thereafter at 100 per cent of the principal amount plus accrued and unpaid interest to the date of redemption.

In February 2025, TCPL issued US$750 million of junior subordinated notes maturing in 2065 with a fixed interest rate of 7.00 per cent per year until June 1, 2030, and resetting every five years thereafter. The rate on the junior subordinated notes will reset every five years commencing June 2030 until June 2065 to the then Five-Year Treasury Rate, as defined in the document governing the subordinated notes, plus 2.614 per cent per annum. The junior subordinated notes are callable at TCPL's option at any time from March 1, 2030 to June 1, 2030 and on each interest payment and reset date thereafter at 100 per cent of the principal amount plus accrued and unpaid interest to the date of redemption.

Pursuant to the terms of the junior subordinated notes issued in 2025, TCPL has the option to defer payment of interest for one or more periods of up to ten years without giving rise to an event of default and without permitting acceleration of payment. TC Energy and TCPL would be prohibited from declaring or paying dividends during any deferral period.

Junior Subordinated Notes Retired/Repaid

In May 2025, TCPL exercised its option to fully repay and retire the US$750 million junior subordinated notes that had a maturity date of 2075, bearing interest at 5.88 per cent to TransCanada Trust (the Trust). The related unamortized debt issue costs of $11 million were included in Interest expense in the Consolidated statement of income. All of the proceeds from the repayment were used by the Trust to fund the redemption price of the US$750 million in aggregate principal amount of outstanding Trust Notes - Series 2015-A, in May 2025 pursuant to their terms.

21. FOREIGN EXCHANGE (GAINS) LOSSES, NET

year ended December 31 (millions of Canadian $)	**2025**	**2024**	**2023**
Derivative instruments held for trading (Note 27)	**(352)**	418	(401)
Other	**195**	(271)	81
	(157)	147	(320)

22. NON-CONTROLLING INTERESTS

The Company's Net income (loss) attributable to non-controlling interests included in the Consolidated statement of income and Non-controlling interests included on the Consolidated balance sheet were as follows:

		Income (Loss) Attributable to Non-Controlling Interests			**Non-Controlling Interests**	
	Non-Controlling Interests Ownership at	**year ended December 31**			**at December 31**	
(millions of Canadian $)	**December 31, 2025**	**2025**	**2024**	**2023**	**2025**	**2024**
Columbia Gas and Columbia Gulf	40% [1]	**631**	571	143	**8,779**	9,844
Portland Natural Gas Transmission System	nil [1]	**—**	30	41	**—**	—
Texas Wind Farms	100% [1,2]	**(38)**	(29)	(38)	**123**	168
TGNH	13.01% [1]	**(18)**	109	—	**702**	756
		575	681	146	**9,604**	10,768

1 Refer to Note 29, Acquisitions and dispositions, for additional information.

2 Tax equity investors own 100 per cent of the Class A Membership Interests, to which a percentage of earnings, tax attributes and cash flows are allocated. TC Energy owns 100 per cent of the Class B Membership Interests.

23. COMMON SHARES

	Number of Shares (thousands)	Amount (millions of Canadian $)
Outstanding at January 1, 2023	1,017,962	28,995
Dividend reinvestment and share purchase plan	19,464	1,003
Exercise of options	62	4
Outstanding at December 31, 2023	1,037,488	30,002
Exercise of options	1,607	99
Outstanding at December 31, 2024	1,039,095	30,101
Exercise of options	**1,740**	**117**
Outstanding at December 31, 2025	**1,040,835**	**30,218**

Common Shares Issued and Outstanding

The Company is authorized to issue an unlimited number of common shares without par value.

Common Shares After Spinoff Transaction

On October 1, 2024, as part of the Spinoff Transaction, TC Energy shareholders received one new TC Energy common share and 0.2 of a South Bow common share in exchange for each TC Energy common share held.

Dividend Reinvestment and Share Purchase Plan

Under the Company's Dividend Reinvestment and Share Purchase Plan (DRP), eligible holders of common and preferred shares of TC Energy can reinvest their dividends and make optional cash payments to obtain additional TC Energy common shares. From August 31, 2022 to July 31, 2023, common shares were issued from treasury at a discount of two per cent to market prices over a specified period.

After July 31, 2023, common shares purchased with reinvested cash dividends under TC Energy's DRP are acquired on the open market at 100 per cent of the weighted average purchase price.

Basic and Diluted Net Income (Loss) per Common Share

Net income (loss) from continuing operations per common share is calculated by dividing Net income (loss) from continuing operations attributable to common shares by the weighted average number of common shares outstanding. Net income (loss) from discontinued operations is calculated by dividing Net income (loss) from discontinued operations by the weighted average number of common shares outstanding. The weighted average number of shares for the diluted earnings per share calculation includes options exercisable under TC Energy's Stock Option Plan and, from August 31, 2022 to July 31, 2023, common shares issuable from treasury under the DRP.

Weighted Average Common Shares Outstanding at December 31 (millions)	**2025**	**2024**	**2023**
Basic	**1,040**	1,038	1,030
Diluted	**1,040**	1,038	1,030

Stock Options

	Number of Options (thousands)	Weighted Average Exercise Prices[1]	Weighted Average Remaining Contractual Life (years)
Options outstanding at January 1, 2025	**4,474**	**$60.69**	
Options exercised	**(1,740)**	**$59.34**	
Options forfeited/expired	**(373)**	**$62.77**	
Options Outstanding at December 31, 2025	**2,361**	**$61.37**	**2.8**
Options Exercisable at December 31, 2025	**1,898**	**$63.22**	**2.4**

1 Exercise prices of TC Energy stock options were adjusted in 2024 for the change in value of the TC Energy common shares following the Spinoff Transaction.

At December 31, 2025, an additional 3,994,688 common shares were reserved for future issuance from treasury under TC Energy's Stock Option Plan. The contractual life of options granted is seven years. Options may be exercised at a price determined at the time the option is awarded and vest equally on the anniversary date in each of the three years following the award. Forfeiture of stock options results from their expiration and, if not previously vested, upon resignation or termination of the option holder's employment. Commencing in 2024, the Company no longer issues stock options to employees or officers. The Company used a binomial model for determining the fair value of options granted and applied the following weighted average assumptions:

year ended December 31	2023
Weighted average fair value	$7.88
Expected life (years)[1]	5.1
Interest rate	2.9%
Volatility[2]	24%
Dividend yield	6.3%

1 Expected life is based on historical exercise activity.
2 Volatility is derived based on the average of both the historical and implied volatility of the Company's common shares.

The amount expensed for stock options, with a corresponding increase in Additional paid-in capital, was $7 million in 2025 (2024 – $6 million; 2023 – $9 million). At December 31, 2025, unrecognized compensation costs related to non-vested stock options were $0.8 million and are expected to be fully recognized over a period of 0.1 years.

The following table summarizes additional stock option information:

year ended December 31 (millions of Canadian $, unless otherwise noted)	2025	2024	2023
Total intrinsic value of options exercised	**20**	17	—
Total fair value of options that have vested	**62**	99	76
Total options vested	**0.8 million**	1.5 million	1.5 million

As at December 31, 2025, the aggregate intrinsic values of the total options exercisable and the total options outstanding were $23 million and $34 million, respectively (2024 - $20 million and $34 million, respectively).

Shareholder Rights Plan

TC Energy's Shareholder Rights Plan is designed to provide the Board of Directors with sufficient time to explore and develop alternatives for maximizing shareholder value in the event of a takeover offer for the Company and to encourage the fair treatment of shareholders in connection with any such offer. Attached to each common share is one right that, under certain circumstances, entitles certain holders to purchase an additional common share of the Company.

24. PREFERRED SHARES

at December 31, 2025	Number of Shares Outstanding (thousands)	Current Yield	Annual Dividend Per Share[1,2]	Redemption Price Per Share	Redemption and Conversion Option Date	Right to Convert Into	Carrying Value December 31[3] 2025 (millions of Canadian $)	2024	2023
Cumulative First Preferred Shares									
Series 1	18,424	4.94% [4]	$1.23475	$25.00	December 31, 2029	Series 2	**456**	456	360
Series 2	3,576	Floating [5]	Floating	$25.00	December 31, 2029	Series 1	**83**	83	179
Series 3	11,715	4.10% [4]	$1.0255	$25.00	June 30, 2030 [6]	Series 4	**289**	246	246
Series 4	2,285	Floating [5]	Floating	$25.00	June 30, 2030 [6]	Series 3	**54**	97	97
Series 5	12,071	1.95%	$0.48725	$25.00	January 30, 2026	Series 6	**294**	294	294
Series 6	1,929	Floating [5]	Floating	$25.00	January 30, 2026	Series 5	**48**	48	48
Series 7	24,000	5.99% [4]	$1.49625	$25.00	April 30, 2029	Series 8	**589**	589	589
Series 9	16,703	5.08% [4]	$1.27	$25.00	October 30, 2029	Series 10	**410**	410	442
Series 10	1,297	Floating [5]	Floating	$25.00	October 30, 2029	Series 9	**32**	32	—
Series 11	—	—	—	—	—	—	**—**	244	244
							2,255	2,499	2,499

1 Each of the even-numbered series of preferred shares, if in existence, will be entitled to receive floating rate cumulative quarterly preferential dividends per share at an annualized rate equal to the 90-day Government of Canada Treasury bill rate (T-Bill rate) plus 1.92 per cent (Series 2), 1.28 per cent (Series 4), 1.54 per cent (Series 6), 2.38 per cent (Series 8), or 2.35 per cent (Series 10). These rates reset quarterly with the then current T-Bill rate.

2 The odd-numbered series of preferred shares, if in existence, will be entitled to receive fixed rate cumulative quarterly preferential dividends, which will reset on the redemption and conversion option date and every fifth year thereafter, at an annualized rate equal to the then Five-Year Government of Canada bond yield plus 1.92 per cent (Series 1), 1.28 per cent (Series 3), 1.54 per cent (Series 5), 2.38 per cent (Series 7), or 2.35 per cent (Series 9).

3 Net of underwriting commissions and deferred income taxes.

4 The fixed rate dividend for Series 3 preferred shares increased from 1.69 per cent to 4.10 per cent on June 30, 2025, and is due to reset on every fifth anniversary thereafter. The fixed rate dividends for Series 1, Series 7 and Series 9 preferred shares increased from 3.48 per cent to 4.94 per cent on December 31, 2024, 3.90 per cent to 5.99 per cent on April 30, 2024 and from 3.76 per cent to 5.08 per cent on October 30, 2024, respectively, and are due to reset on every fifth anniversary thereafter. No Series 7 preferred shares were converted on the April 30, 2024 conversion date.

5 The floating quarterly dividend rate for the Series 2 preferred shares is 4.14 per cent for the period starting December 31, 2025 to, but excluding, March 31, 2026. The floating quarterly dividend rate for the Series 4 preferred shares is 3.50 per cent for the period starting December 31, 2025 to, but excluding, March 31, 2026. The floating quarterly dividend rate for the Series 6 preferred shares is 3.97 per cent for the period starting October 30, 2025 to, but excluding, January 30, 2026 The floating quarterly dividend rate for the Series 10 preferred shares is 4.78 per cent for the period starting October 30, 2025 to, but excluding, January 30, 2026. These rates will reset each quarter going forward.

6 Adjusted to July 2, 2030 to account for applicable business days.

The holders of preferred shares are entitled to receive a fixed or floating cumulative quarterly preferential dividend as and when declared by the Board. The holders will have the right, subject to certain conditions, to convert their first preferred shares of a specified series into first preferred shares of another specified series on the conversion option date and every fifth anniversary thereafter as indicated in the table above.

TC Energy may, at its option, redeem all or a portion of the outstanding preferred shares for the redemption price per share, plus all accrued and unpaid dividends on the applicable redemption option date and on every fifth anniversary thereafter. In addition, Series 2, Series 4, Series 6 and Series 10 preferred shares are redeemable by TC Energy at any time other than on a designated date for $25.50 per share plus all accrued and unpaid dividends on such redemption date.

On November 28, 2025, TC Energy redeemed all 10 million issued and outstanding Series 11 preferred shares at a redemption price of $25.00 per share and paid the final quarterly dividend of $0.2094375 per Series 11 preferred share for the period up to but excluding November 28, 2025. The Company used the proceeds from the October 2025 issuance of US$370 million of Junior Subordinated Notes to finance this preferred share redemption. Prior to the redemption of the Series 11 preferred shares, Series 12 preferred shares were issuable upon conversion of the Series 11 preferred shares, subject to certain conditions, on previously set conversion dates. At the time of the redemption and cancellation of the Series 11 preferred shares, there were no Series 12 preferred shares outstanding.

On June 30, 2025, 104,778 Series 3 preferred shares were converted, on a one-for-one basis, into Series 4 preferred shares and 1,822,829 Series 4 preferred shares were converted, on a one-for-one basis, into Series 3 preferred shares.

On December 31, 2024, 42,200 Series 1 preferred shares were converted, on a one-for-one basis, into Series 2 preferred shares and 3,889,020 Series 2 preferred shares were converted, on a one-for-one basis, into Series 1 preferred shares.

On October 30, 2024, 1,297,203 Series 9 preferred shares were converted, on a one-for-one basis, into Series 10 preferred shares.

25. OTHER COMPREHENSIVE INCOME (LOSS) AND ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)

Components of other comprehensive income (loss), including the portion attributable to non-controlling interests and related tax effects, were as follows:

year ended December 31, 2025 (millions of Canadian $)	**Before Tax Amount**	**Income Tax (Expense) Recovery**	**Net of Tax Amount**
Foreign currency translation gains and losses on net investment in foreign operations	**(970)**	**(8)**	**(978)**
Change in fair value of net investment hedges	**1**	**—**	**1**
Change in fair value of cash flow hedges (Note 27)	**(31)**	**9**	**(22)**
Reclassification to net income of (gains) losses on cash flow hedges	**43**	**(12)**	**31**
Unrealized actuarial gains (losses) on pension and other post-retirement benefit plans	**104**	**(25)**	**79**
Other comprehensive income (loss) on equity investments	**2**	**—**	**2**
Other Comprehensive Income (Loss)	**(851)**	**(36)**	**(887)**

year ended December 31, 2024 (millions of Canadian $)	**Before Tax Amount**	**Income Tax (Expense) Recovery**	**Net of Tax Amount**
Foreign currency translation gains and losses on net investment in foreign operations	1,582	20	1,602
Reclassification of foreign currency translation (gains) losses on net investment on disposal of foreign operations[1]	(25)	—	(25)
Change in fair value of net investment hedges	(23)	5	(18)
Change in fair value of cash flow hedges (Note 27)	46	(11)	35
Reclassification to net income of (gains) losses on cash flow hedges	(20)	4	(16)
Unrealized actuarial gains (losses) on pension and other post-retirement benefit plans	107	(24)	83
Reclassification to net income of actuarial (gains) losses on pension and other post-retirement benefit plans	(6)	—	(6)
Other comprehensive income (loss) on equity investments	230	(57)	173
Other Comprehensive Income (Loss)	1,891	(63)	1,828

1 Represents the controlling and non-controlling currency translation adjustment gains related to PNGTS. Refer to Note 29, Acquisitions and dispositions, for additional information.

year ended December 31, 2023 (millions of Canadian $)	**Before Tax Amount**	**Income Tax (Expense) Recovery**	**Net of Tax Amount**
Foreign currency translation gains and losses on net investment in foreign operations	(1,148)	7	(1,141)
Change in fair value of net investment hedges	23	(6)	17
Reclassification to net income of (gains) losses on cash flow hedges	97	(23)	74
Unrealized actuarial gains (losses) on pension and other post-retirement benefit plans	(15)	4	(11)
Other comprehensive income (loss) on equity investments	(283)	72	(211)
Other Comprehensive Income (Loss)	(1,326)	54	(1,272)

The changes in AOCI by component, net of tax, are as follows:

(millions of Canadian $)	Currency Translation Adjustments	Cash Flow Hedges	Pension and Other Post-Retirement Benefit Plan Adjustments	Equity Investments	Total
AOCI balance at January 1, 2023	441	(109)	(44)	667	955
Other comprehensive income (loss) before reclassifications[1]	(231)	—	(11)	(195)	(437)
Amounts reclassified from AOCI	—	74	—	(16)	58
Net current period other comprehensive income (loss)	(231)	74	(11)	(211)	(379)
Impact of non-controlling interest[2]	(527)	—	—	—	(527)
AOCI balance at December 31, 2023	(317)	(35)	(55)	456	49
Other comprehensive income (loss) before reclassifications[1]	692	35	83	188	998
Amounts reclassified from AOCI[3]	(15)	(16)	(6)	(15)	(52)
Net current period other comprehensive income (loss)	677	19	77	173	946
Impact of non-controlling interest[4]	(21)	—	—	—	(21)
Impact of spinoff of Liquids Pipelines business[5]	(741)	—	—	—	(741)
AOCI balance at December 31, 2024	(402)	(16)	22	629	233
Other comprehensive income (loss) before reclassifications[1]	**(466)**	**(22)**	**79**	**3**	**(406)**
Amounts reclassified from AOCI[6]	**—**	**31**	**—**	**(1)**	**30**
Net current period other comprehensive income (loss)	**(466)**	**9**	**79**	**2**	**(376)**
Impact of non-controlling interest[2]	**348**	**—**	**—**	**—**	**348**
Impact of spinoff of Liquids Pipelines business[5]	**542**	**—**	**—**	**—**	**542**
AOCI balance at December 31, 2025	**22**	**(7)**	**101**	**631**	**747**

1 Other comprehensive income (loss) before reclassifications of currency translation adjustments are net of non-controlling interest losses of $511 million (2024 – gains of $903 million; 2023 – losses of $366 million).

2 Represents the AOCI and adjustment attributable to the 40 per cent non-controlling equity interest in Columbia Gas and Columbia Gulf upon its sale in October 2023. Refer to Note 29, Acquisitions and dispositions and Note 2, Accounting policies, for additional information.

3 Includes the controlling interest of the AOCI attributable to PNGTS recognized in Net gain (loss) on sale of assets upon the sale of PNGTS in August 2024. Refer to Note 29, Acquisitions and dispositions, for additional information.

4 Represents the AOCI attributable to the CFE's 13.01 per cent non-controlling equity interest in TGNH. Refer to Note 29, Acquisitions and dispositions, for additional information.

5 Represents the AOCI and adjustment attributable to the Spinoff Transaction. Refer to Note 4, Discontinued operations and Note 2, Accounting policies, for additional information.

6 Gains related to cash flow hedges reported in AOCI and expected to be reclassified to net income in the next 12 months are estimated to be $9 million ($7 million, net of tax) at December 31, 2025. These estimates assume constant commodity prices, interest rates and foreign exchange rates over time; however, the amounts reclassified will vary based on the actual value of these factors at the date of settlement.

Details about reclassifications out of AOCI into the Consolidated statement of income were as follows:

year ended December 31	Amounts reclassified from AOCI			Affected line item in the Consolidated statement of income
(millions of Canadian $)	**2025**	**2024**	**2023**	
Cash flow hedges				
Commodities	**19**	32	(85)	Revenues (Power and Energy Solutions)
Foreign Exchange	**(50)**	—	—	Interest expense and Foreign exchange gains (losses), net
Interest rate	**(12)**	(12)	(12)	Interest expense
	(43)	20	(97)	Total before tax
	12	(4)	23	Income tax (expense) recovery
	(31)	16	(74)	Net of tax
Pension and other post-retirement benefit plan adjustments				
Amortization of actuarial gains (losses)	**—**	6	—	Plant operating costs and other[1]
	—	6	—	Total before tax
	—	—	—	Income tax (expense) recovery
	—	6	—	Net of tax
Equity investments				
Equity income (loss)	**3**	19	22	Income (loss) from equity investments
	(2)	(4)	(6)	Income tax (expense) recovery
	1	15	16	Net of tax
Currency translation adjustments				
Foreign currency translation gains on disposal of foreign operations	**—**	15	—	Net gain (loss) on sale of assets
	—	—	—	Income tax (expense) recovery
	—	15	—	Net of tax

1 These AOCI components are included in the computation of net benefit cost (recovery). Refer to Note 26, Employee post-retirement benefits, for additional information.

26. EMPLOYEE POST-RETIREMENT BENEFITS

The Company sponsors DB Plans for certain employees. Pension benefits provided under the DB Plans are generally based on years of service and highest average earnings over three to five consecutive years of employment. Effective January 1, 2019, there were certain amendments made to the Canadian DB Plan for new members. Subsequent to that date, benefits provided for new members were based on years of service and highest average earnings over five consecutive years of employment. Upon commencement of retirement, pension benefits in the Canadian DB Plan increase annually by a portion of the increase in the Consumer Price Index for employees hired prior to January 1, 2019. On January 1, 2024 the Canadian DB Plans were closed to new entrants. Employees hired on and after January 1, 2024 will participate in the Canadian DC Plan.

On January 1, 2025, there was an amendment to the Canadian OPEB Plan which closed the plan for any eligible active employees that did not retire by December 31, 2024. All active employees who no longer meet the eligibility for the OPEB Plan will be eligible for a new plan that provides an annual health spending account to retirees and their dependents from retirement to age 65.

The Company's U.S. DB Plan is closed to non-union new entrants and all non-union hires participate in the DC Plan. Net actuarial gains or losses are amortized out of AOCI over the EARSL of Plan participants, which was approximately eight years at December 31, 2025 (2024 – nine years; 2023 – nine years).

The Company also provides its employees with DC Plans and savings plans in Canada, DC Plans in Mexico, DC Plans consisting of a 401(k) Plan in the U.S. and post-employment benefits other than pensions, including termination benefits and life insurance and medical benefits beyond those provided by government-sponsored plans. Net actuarial gains or losses for the plans are amortized out of AOCI over the EARSL of employees, which was approximately 11 years at December 31, 2025 (2024 – 12 years and 2023 – 12 years). In 2025, the Company expensed $72 million (2024 – $71 million and 2023 – $64 million) for the savings and DC Plans.

As part of the Spinoff Transaction, certain TC Energy employees became employees of South Bow. Prior to the Spinoff Transaction, these employees in Canada and the U.S. participated in DB Plans, DC Plans and savings plans, as applicable. Effective October 1, 2024, the benefit obligations under the DB Plans in respect of the employees moving from TC Energy to South Bow were transferred to South Bow. An asset transfer application related to the Canadian DB Plan outlining the proposed transfer of assets from TC Energy to South Bow has received regulatory approval. During the year ended December 31, 2025, $105 million was transferred to South Bow. As at December 31, 2025, $17 million of assets in the Canadian DB Plan remain in the TC Energy DB Plan trust and are reflected as Current assets of discontinued operations with a corresponding obligation to South Bow reflected as Current liabilities of discontinued operations on the Consolidated balance sheet. The Company expects the remaining assets to be fully transferred mid-2026. As at December 31, 2024, the assets related to the U.S. DB Plan were fully transferred to South Bow.

Total cash contributions by the Company for employee post-retirement benefits were as follows:

year ended December 31 (millions of Canadian $)	**2025**	**2024**	**2023**
DB Plans	**—**	—	28
Other post-retirement benefit plans	**8**	8	9
Savings and DC Plans	**72**	71	64
	80	79	101

Current Canadian pension legislation allows for partial funding of solvency requirements over a number of years through letters of credit in lieu of cash contributions, up to certain limits. Total letters of credit provided to the Canadian DB plan at December 31, 2025 was nil (2024 – $111 million; 2023 – $244 million).

The most recent actuarial valuation of the pension plans for funding purposes was as at January 1, 2025 and the next required valuation is at January 1, 2026.

The Company's funded status was comprised of the following:

at December 31 (millions of Canadian $)	Pension Benefit Plans 2025	Pension Benefit Plans 2024	Other Post-Retirement Benefit Plans 2025	Other Post-Retirement Benefit Plans 2024
Change in Benefit Obligation[1]				
Benefit obligation – beginning of year	**3,342**	3,356	**288**	285
Service cost	**101**	108	**1**	1
Interest cost	**162**	160	**15**	14
Employee contributions	**11**	11	**2**	2
Benefits paid	**(228)**	(194)	**(22)**	(24)
Actuarial (gain) loss[2]	**(80)**	(39)	**(26)**	(5)
South Bow - transition of benefit obligation[3]	**—**	(118)	**—**	(1)
Foreign exchange rate changes	**(35)**	58	**(9)**	16
Benefit obligation – end of year	**3,273**	3,342	**249**	288
Change in Plan Assets				
Plan assets at fair value – beginning of year	**3,948**	3,697	**339**	358
Actual return on plan assets	**390**	485	**22**	17
Employer contributions[4,5]	**—**	—	**8**	(41)
Employee contributions	**11**	11	**2**	2
Benefits paid	**(228)**	(194)	**(22)**	(25)
South Bow - transition of plan assets[3]	**—**	(119)	**—**	—
Foreign exchange rate changes	**(40)**	68	**(16)**	28
Plan assets at fair value – end of year	**4,081**	3,948	**333**	339
Funded Status – Plan Surplus	**808**	606	**84**	51

1 The benefit obligation for the Company's pension benefit plans represents the projected benefit obligation. The benefit obligation for the Company's other post-retirement benefit plans represents the accumulated post-retirement benefit obligation.
2 The increase in the actuarial (gain) loss on the defined benefit plan obligation is primarily attributable to an increase in the weighted discount rate from 4.90 per cent in 2024 to 5.10 per cent in 2025 and an increase in the rate of return. The actuarial (gain) loss on the OPEB Plan obligation is primarily due to changes in demographic assumptions.
3 Reflects the impact of the Spinoff Transaction of the Liquids Pipelines business on October 1, 2024.
4 The Company reduced letters of credit by $111 million in the Canadian DB Plan (2024 – $133 million) for funding purposes.
5 OPEB surplus of nil (2024 - $49 million) was transferred to pay future active employee medical expenses.

Additional pension benefit plan assets were as follows:

at December 31 (millions of Canadian $)	Pension Benefit Plans 2025	Pension Benefit Plans 2024
TC Energy plan assets at fair value	**4,081**	3,948
South Bow plan assets held in trust[1]	**17**	110
Plan assets at fair value – end of year	**4,098**	4,058

1 Related to the transfer of pension assets to South Bow. The remaining South Bow pension assets will be adjusted to fair value on the date of the transfer. At December 31, 2025, $17 million is reflected in Other current assets of discontinued operations (2024 - $110 million reflected in Other long-term assets of discontinued operations).

The amounts recognized on the Company's Consolidated balance sheet for its DB Plans and other post-retirement benefits plans were as follows:

at December 31	Pension Benefit Plans		Other Post-Retirement Benefit Plans	
(millions of Canadian $)	**2025**	2024	**2025**	2024
Other long-term assets (Note 14)	**808**	606	**159**	152
Accounts payable and other	**—**	—	**(6)**	(7)
Other long-term liabilities (Note 17)	**—**	—	**(69)**	(94)
	808	606	**84**	51

Included in the above benefit obligation and fair value of plan assets were the following amounts for plans that were not fully funded:

at December 31	Pension Benefit Plans		Other Post-Retirement Benefit Plans	
(millions of Canadian $)	**2025**	2024	**2025**	2024
Projected benefit obligation[1]	**—**	—	**(76)**	(101)
Plan assets at fair value	**—**	—	**—**	—
Funded Status – Plan Deficit	**—**	—	**(76)**	(101)

1 The projected benefit obligation for the pension benefit plans differs from the accumulated benefit obligation in that it includes an assumption with respect to future compensation levels.

The funded status based on the accumulated benefit obligation for all DB Plans was as follows:

at December 31		
(millions of Canadian $)	**2025**	2024
Accumulated benefit obligation	**(3,086)**	(3,097)
Plan assets at fair value[1]	**4,098**	4,058
Funded Status – Plan Surplus	**1,012**	961

1 Includes an estimated $17 million (2024 - $110 million) for future transfer to South Bow. The remaining South Bow pension assets will be adjusted to fair value on the date of the transfer.

The Company's DB Plans with respect to accumulated benefit obligations and the fair value of plan assets were fully funded as at December 31, 2025 and December 31, 2024.

The Company pension plans' weighted average asset allocations and target allocations by asset category were as follows:

at December 31	Percentage of Plan Assets		Target Allocations
	2025	2024	**2025**
Fixed income securities	**45%**	37%	**30% to 55%**
Equity securities	**40%**	49%	**20% to 55%**
Other investments	**15%**	14%	**10% to 35%**
	100%	100%	

Fixed income and equity securities include the Company's and its related parties debt and common shares as follows:

at December 31			Percentage of Plan Assets	
(millions of Canadian $)	**2025**	**2024**	**2025**	**2024**
Fixed income securities	**26**	44	**0.6%**	1.1%
Equity securities	**2**	3	**0.1%**	0.1%

Pension plan assets are managed on a going concern basis, subject to legislative restrictions, and are diversified across asset classes to maximize returns at an acceptable level of risk. Asset mix strategies consider plan demographics and may include traditional equity and debt securities as well as alternative assets such as infrastructure, private equity, real estate and derivatives to diversify risk. Derivatives are not used for speculative purposes and may be used to hedge certain liabilities.

All investments are measured at fair value using market prices. Where the fair value cannot be readily determined by reference to generally available price quotations, the fair value is determined by considering the discounted cash flows on a risk-adjusted basis and by comparison to similar assets which are publicly traded. In Level I, the fair value of assets is determined by reference to quoted prices in active markets for identical assets that the Company has the ability to access at the measurement date. In Level II, the fair value of assets is determined using valuation techniques such as option pricing models and extrapolation using significant inputs which are observable directly or indirectly. In Level III, the fair value of assets is determined using a market approach based on inputs that are unobservable and significant to the overall fair value measurement.

The following table presents plan assets for DB Plans and OPEB Plans measured at fair value, which have been categorized into the three categories based on a fair value hierarchy. Refer to Note 27, Risk management and financial instruments, for additional information.

at December 31 (millions of Canadian $, unless otherwise noted)	Quoted Prices in Active Markets (Level I)		Significant Other Observable Inputs (Level II)		Significant Unobservable Inputs (Level III)		Total		Percentage of Total Portfolio	
	2025	**2024**	**2025**	**2024**	**2025**	**2024**	**2025**	**2024**	**2025**	**2024**
Asset Category[1]										
Cash and Cash Equivalents	**130**	138	**—**	—	**—**	—	**130**	138	**3%**	3%
Equity Securities:										
Canadian	**129**	128	**—**	—	**—**	—	**129**	128	**3%**	3%
U.S.	**969**	1,234	**—**	—	**—**	—	**969**	1,234	**22%**	28%
International	**107**	182	**220**	209	**—**	—	**327**	391	**7%**	9%
Global	**—**	—	**104**	100	**—**	—	**104**	100	**2%**	2%
Emerging	**33**	66	**132**	150	**—**	—	**165**	216	**4%**	5%
Fixed Income Securities:										
Canadian Bonds:										
Federal	**—**	—	**16**	55	**—**	—	**16**	55	**—**	1%
Provincial	**—**	—	**514**	312	**—**	—	**514**	312	**12%**	7%
Municipal	**—**	—	**19**	14	**—**	—	**19**	14	**—**	—
Corporate	**—**	—	**483**	323	**—**	—	**483**	323	**11%**	7%
U.S. Bonds:										
Federal	**147**	151	**260**	255	**—**	—	**407**	406	**9%**	9%
Municipal	**—**	—	**1**	1	**—**	—	**1**	1	**—**	—
Corporate	**185**	246	**193**	158	**—**	—	**378**	404	**9%**	9%
International:										
Government	**3**	4	**19**	17	**—**	—	**22**	21	**1%**	1%
Corporate	**—**	—	**96**	66	**—**	—	**96**	66	**2%**	2%
Mortgage backed	**40**	37	**20**	23	**—**	—	**60**	60	**1%**	1%
Net forward contracts	**—**	—	**(184)**	(201)	**—**	—	**(184)**	(201)	**(4%)**	(4%)
Other Investments:										
Real estate	**—**	—	**—**	—	**292**	276	**292**	276	**7%**	6%
Infrastructure	**—**	—	**—**	—	**315**	282	**315**	282	**7%**	7%
Private equity funds	**—**	—	**—**	—	**55**	32	**55**	32	**1%**	1%
Funds held on deposit	**130**	138	**—**	—	**—**	—	**130**	138	**3%**	3%
Derivatives	**—**	—	**3**	1	**—**	—	**3**	1	**—**	—
	1,873	2,324	**1,896**	1,483	**662**	590	**4,431**	4,397	**100%**	100%

1 Includes $17 million (2024 - $110 million) for future transfer to South Bow.

The following table presents the net change in the Level III fair value category:

(millions of Canadian $, pre-tax)	
Balance at December 31, 2023	562
Purchases and sales	(15)
Realized and unrealized gains (losses)	43
Balance at December 31, 2024	590
Purchases and sales	**59**
Realized and unrealized gains (losses)	**13**
Balance at December 31, 2025	**662**

In 2026, the Company expects to make funding contributions of $8 million for the other post-retirement benefit plans, approximately $76 million for the savings plans and DC Plans and no contributions for the DB Plans. The Company is not expecting to issue any additional letters of credit for the funding of solvency requirements to the Canadian DB plan in 2026.

The following are estimated future benefit payments, which reflect expected future service:

at December 31 (millions of Canadian $)	**Pension Benefits**	**Other Post-Retirement Benefits**
2026	223	22
2027	224	22
2028	226	22
2029	228	21
2030	230	21
2031 to 2035	1,158	98

The rate used to discount pension and other post-retirement benefit plan obligations was developed based on a yield curve of primarily corporate AA bond yields at December 31, 2025. This yield curve is used to develop spot rates that vary based on the duration of the obligations. The estimated future cash flows for the pension and other post-retirement benefit obligations were matched to the corresponding rates on the spot rate curve to derive a weighted average discount rate.

The significant weighted average actuarial assumptions adopted in measuring the Company's benefit obligations were as follows:

at December 31	**Pension Benefit Plans**		**Other Post-Retirement Benefit Plans**	
	2025	**2024**	**2025**	**2024**
Discount rate	**5.10%**	4.90%	**5.45%**	5.45%
Rate of compensation increase	**3.05%**	3.05%	**—**	—

The significant weighted average actuarial assumptions adopted in measuring the Company's net benefit plan costs were as follows:

year ended December 31	**Pension Benefit Plans**			**Other Post-Retirement Benefit Plans**		
	2025	**2024**	**2023**	**2025**	**2024**	**2023**
Discount rate	**4.90%**	4.75%	5.15%	**5.45%**	5.15%	5.45%
Expected long-term rate of return on plan assets	**6.75%**	6.60%	6.45%	**4.75%**	4.50%	4.50%
Rate of compensation increase	**3.05%**	3.15%	3.25%	**—**	—	—

The overall expected long-term rate of return on plan assets is based on historical and projected rates of return for the portfolio in aggregate and for each asset class in the portfolio. Assumed projected rates of return are selected after analyzing historical experience and estimating future levels and volatility of returns. Asset class benchmark returns and asset mix are also considered in determining the overall expected rate of return. The discount rate is based on market interest rates of high-quality bonds that match the timing and benefits expected to be paid under each plan.

A 6.70 per cent weighted-average annual rate of increase in the per capita cost of covered health care benefits was assumed for 2026 measurement purposes. The rate was assumed to decrease gradually to 4.85 per cent by 2036 and remain at this level thereafter.

The net benefit cost recognized for the Company's pension benefit plans and other post-retirement benefit plans was as follows:

year ended December 31	**Pension Benefit Plans**			**Other Post-Retirement Benefit Plans**		
(millions of Canadian $)	**2025**	**2024**	**2023**	**2025**	**2024**	**2023**
Service cost[1]	**101**	108	93	**1**	1	3
Other components of net benefit cost[1]						
Interest cost	**162**	160	158	**15**	14	16
Expected return on plan assets	**(250)**	(248)	(234)	**(16)**	(14)	(16)
Amortization of past service cost	**—**	—	—	**(2)**	—	—
Amortization of regulatory asset	**—**	—	—	**—**	(2)	—
	(88)	(88)	(76)	**(3)**	(2)	—
Net Benefit Cost Recognized	**13**	20	17	**(2)**	(1)	3

1 Service cost and other components of net benefit cost are included in Plant operating costs and other in the Consolidated statement of income.

Pre-tax amounts recognized in AOCI were as follows:

at December 31	**2025**		**2024**		**2023**	
(millions of Canadian $)	**Pension Benefits**	**Other Post-Retirement Benefits**	**Pension Benefits**	**Other Post-Retirement Benefits**	**Pension Benefits**	**Other Post-Retirement Benefits**
Net loss (gain)	**(114)**	**(13)**	(24)	—	71	6

Pre-tax amounts recognized in OCI were as follows:

year ended December 31	**2025**		**2024**		**2023**	
(millions of Canadian $)	**Pension Benefits**	**Other Post-Retirement Benefits**	**Pension Benefits**	**Other Post-Retirement Benefits**	**Pension Benefits**	**Other Post-Retirement Benefits**
Amortization of net gain (loss) from AOCI to net income	**—**	**—**	6	—	—	—
Funded status adjustment	**(91)**	**(13)**	(101)	(6)	33	(18)
	(91)	**(13)**	(95)	(6)	33	(18)

27. RISK MANAGEMENT AND FINANCIAL INSTRUMENTS

Risk Management Overview

TC Energy has exposure to various financial risks and has strategies, policies and limits in place to manage the impact of these risks on its earnings, cash flows and, ultimately, shareholder value.

Risk management strategies, policies and limits are designed to ensure TC Energy's risks and related exposures are in line with the Company's business objectives and risk tolerance. TC Energy's risks are managed within limits that are established by the Company's Board, implemented by senior management and monitored by the Company's risk management, internal audit and business segment groups. The Board's Audit Committee oversees how management monitors compliance with risk management policies and procedures and oversees management's review of the adequacy of the risk management framework.

Market Risk

The Company constructs and invests in energy infrastructure projects, purchases and sells commodities, issues short- and long-term debt, including amounts in foreign currencies and invests in foreign operations. Certain of these activities expose the Company to market risk from changes in commodity prices, foreign exchange rates and interest rates, which may affect the Company's earnings, cash flows and the value of its financial assets and liabilities. The Company assesses contracts used to manage market risk to determine whether all, or a portion, meets the definition of a derivative.

Derivative contracts the Company uses to assist in managing exposure to market risk may include the following:

- forwards and futures contracts – agreements to purchase or sell a specific financial instrument or commodity at a specified price and date in the future
- swaps – agreements between two parties to exchange streams of payments over time according to specified terms
- options – agreements that convey the right, but not the obligation of the purchaser to buy or sell a specific amount of a financial instrument or commodity at a fixed price, either at a fixed date or at any time within a specified period.

Commodity price risk

The following strategies may be used to manage the Company's exposure to market risk resulting from commodity price risk management activities in the Company's non-regulated businesses:

- in the Company's natural gas marketing business, TC Energy enters into natural gas transportation and storage contracts as well as natural gas purchase and sale agreements. The Company manages exposure on these contracts using financial instruments and hedging activities to offset market price volatility
- in the Company's power businesses, TC Energy manages the exposure to fluctuating commodity prices through long-term contracts and hedging activities including selling and purchasing electricity and natural gas in forward markets
- in the Company's non-regulated natural gas storage business, TC Energy's exposure to seasonal natural gas price spreads is managed with a portfolio of third-party storage capacity contracts and through offsetting purchases and sales of natural gas in forward markets to lock in future positive margins.

Lower natural gas and electricity prices could lead to reduced investment in the development, expansion and production of these commodities. A reduction in the demand for these commodities could negatively impact opportunities to expand the Company's asset base and/or re-contract with TC Energy's shippers and customers as contractual agreements expire.

Physical and transition risks

Climate-related physical and transition risks may influence demand for, or the operation of, TC Energy's assets, which could affect the Company's financial performance. TC Energy evaluates the financial resilience of its asset portfolio against a range of future pricing and supply and demand outcomes as part of the Company's strategic planning process.

TC Energy manages exposure to climate-related transition risks and resulting policy changes through its business model, which is based on a long-term, low-risk strategy whereby the majority of TC Energy's earnings are underpinned by regulated cost-of-service arrangements and/or long-term contracts. Physical and transition risks are factored into capital planning, enterprise risk management, financial risk management and operational activities. In addition, the Company is actively working to reduce methane emissions intensity from our natural gas transmission and gas storage assets.

Interest rate risk

TC Energy utilizes short- and long-term debt to finance its operations which exposes the Company to interest rate risk. TC Energy typically pays fixed rates of interest on its long-term debt and floating rates on short-term debt including its commercial paper programs and amounts drawn on its credit facilities. A small portion of TC Energy's long-term debt bears interest at floating rates. In addition, the Company is exposed to interest rate risk on financial instruments and contractual obligations containing variable interest rate components. The Company actively manages its interest rate risk using interest rate derivatives.

Foreign exchange risk

Certain of TC Energy's businesses generate all or most of their earnings in U.S. dollars and, since the Company reports its financial results in Canadian dollars, changes in the value of the U.S. dollar against the Canadian dollar can affect its net income. This exposure grows as the Company's U.S. dollar-denominated operations grow. A portion of this risk is offset by interest expense on U.S. dollar-denominated debt. The balance of the exposure is actively managed on a rolling basis up to three years in advance using foreign exchange derivatives; however, the natural exposure beyond that period remains.

A portion of the Company's Mexico Natural Gas Pipelines monetary assets and liabilities are peso-denominated, while TC Energy's Mexico operations' financial results are denominated in U.S. dollars. These peso-denominated balances are revalued to U.S. dollars and, as a result, changes in the value of the Mexican peso against the U.S. dollar can affect the Company's net income. In addition, foreign exchange gains or losses calculated for Mexico income tax purposes on the revaluation of U.S. dollar-denominated monetary assets and liabilities result in a peso-denominated income tax exposure for these entities, leading to fluctuations in Income (loss) from equity investments and Income tax expense (recovery). These exposures are actively managed using foreign exchange derivatives, although some unhedged exposure remains.

Net investment in foreign operations

The Company hedges a portion of its net investment in foreign operations (on an after-tax basis) with U.S. dollar-denominated debt and cross-currency interest rate swaps as appropriate.

The fair values and notional amounts for the derivatives designated as a net investment hedge were as follows:

at December 31	2025		2024	
(millions of Canadian $, unless otherwise noted)	Fair Value	Notional Amount	Fair Value[1,2]	Notional Amount
U.S. dollar cross-currency interest rate swaps[3]	—	—	(11)	US 100

1 Fair value equals carrying value.

2 No amounts have been excluded from the assessment of hedge effectiveness.

3 In 2025 and 2024, Net income (loss) included net realized gains of less than $1 million related to the interest component of cross-currency swap settlements which are reported within Interest expense in the Consolidated statement of income.

The notional amounts and fair values of U.S. dollar-denominated debt designated as a net investment hedge were as follows:

at December 31 (millions of Canadian $, unless otherwise noted)	2025	2024
Notional amount	**25,700 (US 18,700)**	26,000 (US 18,000)
Fair value	**25,800 (US 18,800)**	25,700 (US 17,800)

Counterparty Credit Risk

TC Energy's exposure to counterparty credit risk includes its cash and cash equivalents, accounts receivable, available-for-sale assets, the fair value of derivative assets, net investment in leases and certain contract assets in Mexico.

At times, the Company's counterparties may endure financial challenges resulting from commodity price and market volatility, economic instability and political or regulatory changes. In addition to actively monitoring these situations, there are a number of factors that reduce TC Energy's counterparty credit risk exposure in the event of default, including:

- contractual rights and remedies together with the utilization of contractually-based financial assurances
- current regulatory frameworks governing certain TC Energy operations
- the competitive position of the Company's assets and the demand for the Company's services
- potential recovery of unpaid amounts through bankruptcy and similar proceedings.

The Company reviews financial assets carried at amortized cost for impairment using the lifetime expected loss of the financial asset at initial recognition and throughout the life of the financial asset. TC Energy uses historical credit loss and recovery data, adjusted for management's judgment regarding current economic and credit conditions, along with reasonable and supportable forecasts to determine any impairment, which is recognized in Plant operating costs and other.

The Company's net investment in leases and certain contract assets are financial assets subject to ECL. TC Energy's methodology for assessing the ECL regarding these financial assets includes consideration of the probability of default (the probability that the customer will default on its obligation), the loss given default (the economic loss as a proportion of the financial asset balance in the event of a default) and the exposure at default (the financial asset balance at the time of a hypothetical default) with one-year forward-looking information that includes assumptions for future macroeconomic conditions under three probability-weighted future scenarios.

The macroeconomic factors considered most relevant to the Company's net investment in leases and contract assets include Mexico's GDP, Mexico's government debt to GDP and Mexico's inflation. The ECL amount is updated at each reporting date to reflect changes in assumptions and forecasts for future economic conditions.

For the year ended December 31, 2025, the Company recorded an $84 million ECL expense (2024 – $23 million recovery; 2023 - $73 million recovery) with respect to the net investment in leases associated with the in-service TGNH pipelines and $1 million ECL recovery (2024 – $1 million expense; 2023 – $10 million recovery) for contract assets related to certain other Mexico natural gas pipelines. At December 31, 2025, the balance of the ECL provision was $141 million (2024 – $59 million) with respect to the net investment in leases associated with in-service TGNH pipelines. The ECL provision is driven primarily by a probability of default measure for the counterparty, which is calculated using information published by an external third party.

Other than the ECL provision noted above, the Company had no significant credit losses at December 31, 2025 and 2024. At December 31, 2025 and 2024, there were no significant credit risk concentrations and no significant amounts past due or impaired.

TC Energy has significant credit and performance exposure to financial institutions that hold cash deposits and provide committed credit lines and letters of credit that help manage the Company's exposure to counterparties and provide liquidity in commodity, foreign exchange and interest rate derivative markets. TC Energy's portfolio of financial sector exposure consists primarily of highly-rated investment grade, systemically important financial institutions.

Non-Derivative Financial Instruments

Fair value of non-derivative financial instruments

Available-for-sale assets are recorded at fair value which is calculated using quoted market prices where available in addition to the Company's LMCI equity securities which are classified in Level I of the fair value hierarchy. Certain other non-derivative financial instruments included in Cash and cash equivalents, Accounts receivable, Other current assets, Net investment in leases, Restricted investments, Other long-term assets, Notes payable, Accounts payable and other, Dividends payable, Accrued interest and Other long-term liabilities have carrying amounts that approximate their fair value due to the nature of the item or the short time to maturity.

Credit risk has been taken into consideration when calculating the fair value of non-derivative financial instruments.

Balance sheet presentation of non-derivative financial instruments

The following table details the fair value of non-derivative financial instruments, excluding those where carrying amounts approximate fair value, and would be classified in Level II of the fair value hierarchy:

at December 31	2025		2024	
(millions of Canadian $)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-term debt, including current portion (Note 19)[1,2]	**(46,792)**	**(47,720)**	(47,931)	(48,318)
Junior subordinated notes (Note 20)	**(12,094)**	**(12,061)**	(11,048)	(10,824)
	(58,886)	**(59,781)**	(58,979)	(59,142)

1 Long-term debt is recorded at amortized cost, except for $4.0 billion (2024 – $4.0 billion) that is attributed to hedged risk and recorded at fair value.

2 Net income (loss) for 2025 included unrealized losses of $122 million (2024 – unrealized gains of $128 million) for fair value adjustments attributable to the hedged interest rate risk associated with interest rate swap fair value hedging.

The following tables summarize additional information about the Company's restricted investments that were classified as available-for-sale assets and equity securities with readily determinable fair values:

at December 31	2025		2024	
(millions of Canadian $)	LMCI Restricted Investments	Other Restricted Investments[1]	LMCI Restricted Investments	Other Restricted Investments[1]
Fair value of fixed income securities[2,3]				
Maturing within 1 year	**—**	**94**	—	33
Maturing within 1-5 years	**26**	**251**	3	256
Maturing within 5-10 years	**1,846**	**4**	1,578	—
Maturing after 10 years	**—**	**16**	—	—
Fair value of equity securities[2,4]	**1,252**	**94**	1,070	64
	3,124	**459**	2,651	353

1 Other restricted investments have been set aside to fund insurance claim losses to be paid by the Company's wholly-owned captive insurance subsidiary and, in 2025, funds have also been set aside to pay for certain active employee medical benefits.

2 Available-for-sale assets and equity securities with readily determinable fair values are recorded at fair value and included in Other current assets and Restricted investments on the Company's Consolidated balance sheet.

3 Classified in Level II of the fair value hierarchy.

4 Classified in Level I of the fair value hierarchy.

year ended December 31	2025		2024		2023	
(millions of Canadian $)	LMCI Restricted Investments[1]	Other Restricted Investments[2]	LMCI Restricted Investments[1]	Other Restricted Investments[2]	LMCI Restricted Investments[1]	Other Restricted Investments[2]
Net unrealized gains (losses)	**167**	**(1)**	218	9	179	13
Net realized gains (losses)[3]	**21**	**22**	3	2	(28)	—

1 Unrealized and realized gains (losses) arising from changes in the fair value of LMCI restricted investments impact the subsequent amounts to be collected through tolls to cover future pipeline abandonment costs. As a result, the Company records these gains and losses as regulatory liabilities or regulatory assets.

2 Unrealized and realized gains (losses) on other restricted investments are included in Interest income and other in the Company's Consolidated statement of income.

3 Realized gains (losses) on the sale of LMCI restricted investments are determined using the average cost basis.

Derivative Instruments

Fair value of derivative instruments

The fair value of foreign exchange and interest rate derivatives has been calculated using the income approach which uses year-end market rates and applies a discounted cash flow valuation model. The fair value of commodity derivatives has been calculated using quoted market prices where available. In the absence of quoted market prices, third-party broker quotes or other valuation techniques have been used. The fair value of options has been calculated using the Black-Scholes pricing model. Credit risk has been taken into consideration when calculating the fair value of derivative instruments. Unrealized gains and losses on derivative instruments are not necessarily representative of the amounts that will be realized on settlement.

In some cases, even though the derivatives are considered to be effective economic hedges, they do not meet the specific criteria for hedge accounting treatment or are not designated as a hedge and are accounted for at fair value with changes in fair value recorded in net income in the period of change. This may expose the Company to increased variability in reported earnings because the fair value of the derivative instruments can fluctuate significantly from period to period.

The recognition of gains and losses on derivatives for Canadian natural gas regulated pipeline exposures is determined through the regulatory process. Gains and losses arising from changes in the fair value of derivatives accounted for as part of RRA, including those that qualify for hedge accounting treatment, are expected to be refunded or recovered through the tolls charged by the Company. As a result, these gains and losses are deferred as regulatory liabilities or regulatory assets and are refunded to or collected from the rate payers in subsequent years when the derivative settles.

Balance sheet presentation of derivative instruments

The balance sheet classification of the fair value of derivative instruments was as follows:

at December 31, 2025 (millions of Canadian $)	Cash Flow Hedges	Fair Value Hedges	Held for Trading	Total Fair Value of Derivative Instruments[1]
Other current assets (Note 7)				
Commodities[2]	13	—	371	384
Foreign exchange	9	—	42	51
Interest rate	—	3	—	3
	22	3	413	438
Other long-term assets (Note 14)				
Commodities[2]	2	—	122	124
Foreign exchange	—	—	15	15
Interest rate	—	22	—	22
	2	22	137	161
Total Derivative Assets	24	25	550	599
Accounts payable and other (Note 16)				
Commodities[2]	(1)	—	(341)	(342)
Foreign exchange	—	—	(30)	(30)
Interest rate	—	(8)	—	(8)
	(1)	(8)	(371)	(380)
Other long-term liabilities (Note 17)				
Commodities[2]	(1)	—	(61)	(62)
Foreign exchange	(51)	—	(2)	(53)
Interest rate	—	(34)	—	(34)
	(52)	(34)	(63)	(149)
Total Derivative Liabilities	(53)	(42)	(434)	(529)
Total Derivatives	(29)	(17)	116	70

1 Fair value equals carrying value.

2 Includes purchases and sales of power and natural gas.

The balance sheet classification of the fair value of derivative instruments was as follows:

at December 31, 2024 (millions of Canadian $)	Cash Flow Hedges	Fair Value Hedges	Net Investment Hedges	Held for Trading	Total Fair Value of Derivative Instruments[1]
Other current assets (Note 7)					
Commodities[2]	18	—	—	287	305
Foreign exchange	—	—	—	42	42
	18	—	—	329	347
Other long-term assets (Note 14)					
Commodities[2]	9	—	—	104	113
Foreign exchange	—	—	—	9	9
	9	—	—	113	122
Total Derivative Assets	27	—	—	442	469
Accounts payable and other (Note 16)					
Commodities[2]	(1)	—	—	(291)	(292)
Foreign exchange	—	—	(11)	(183)	(194)
Interest rate	—	(21)	—	—	(21)
	(1)	(21)	(11)	(474)	(507)
Other long-term liabilities (Note 17)					
Commodities[2]	(1)	—	—	(46)	(47)
Foreign exchange	—	—	—	(44)	(44)
Interest rate	—	(118)	—	—	(118)
	(1)	(118)	—	(90)	(209)
Total Derivative Liabilities	(2)	(139)	(11)	(564)	(716)
Total Derivatives	25	(139)	(11)	(122)	(247)

1 Fair value equals carrying value.
2 Includes purchases and sales of power and natural gas.

The majority of derivative instruments held for trading have been entered into for risk management purposes and all are subject to the Company's risk management strategies, policies and limits. These include derivatives that have not been designated as hedges or do not qualify for hedge accounting treatment but have been entered into as economic hedges to manage the Company's exposures to market risk.

Non-derivatives in fair value hedging relationships

The following table details amounts recorded on the Consolidated balance sheet in relation to cumulative adjustments for fair value hedges included in the carrying amount of the hedged liabilities:

at December 31	Carrying Amount		Fair Value Hedging Adjustments[1]	
(millions of Canadian $)	**2025**	2024	**2025**	2024
Long-term debt	**(4,068)**	(3,935)	**(22)**	98

1 At December 31, 2025, adjustments for discontinued hedging relationships included in this balance was a liability of $39 million (2024 – $41 million).

Notional and maturity summary

The maturity and notional amount or quantity outstanding related to the Company's derivative instruments excluding hedges of the net investment in foreign operations was as follows:

at December 31, 2025	Power	Natural Gas	Foreign Exchange	Interest Rate
Net sales (purchases)[1]	**10,221**	**26**	**—**	**—**
Millions of U.S. dollars	**—**	**—**	**6,342**	**2,950**
Millions of Mexican pesos	**—**	**—**	**15,750**	**—**
Maturity dates	**2026-2044**	**2026-2032**	**2026-2030**	**2030-2034**

1 Volumes for power and natural gas derivatives are in GWh and Bcf, respectively.

at December 31, 2024	Power	Natural Gas	Foreign Exchange	Interest Rate
Net sales (purchases)[1]	10,192	53	—	—
Millions of U.S. dollars	—	—	5,648	2,800
Millions of Mexican pesos	—	—	16,750	—
Maturity dates	2025-2044	2025-2031	2025-2027	2030-2034

1 Volumes for power and natural gas derivatives are in GWh and Bcf, respectively.

Unrealized and Realized Gains (Losses) on Derivative Instruments

The following summary does not include hedges of the net investment in foreign operations:

year ended December 31 (millions of Canadian $)	2025	2024	2023
Derivative Instruments Held for Trading[1]			
Unrealized gains (losses) in the year			
Commodities[2]	**25**	(71)	132
Foreign exchange (Note 21)	**210**	(266)	246
Interest rate	**—**	(71)	—
Realized gains (losses) in the year			
Commodities	**(10)**	199	192
Foreign exchange (Note 21)	**142**	(152)	155
Interest rate	**8**	29	—
Derivative Instruments in Hedging Relationships			
Realized gains (losses) in the year			
Commodities	**24**	33	(2)
Foreign exchange	**10**	—	—
Interest rate	**(30)**	(52)	(43)

1 Realized and unrealized gains (losses) on held-for-trading derivative instruments used to purchase and sell commodities are included on a net basis in Revenues in the Consolidated statement of income. Realized and unrealized gains (losses) on foreign exchange and interest rate held-for-trading derivative instruments are included on a net basis in Foreign exchange (gains) losses, net and Interest expense, respectively, in the Consolidated statement of income.

2 In 2025, unrealized gains of $2 million were reclassified to Net Income (loss) from AOCI related to discontinued cash flow hedges (2024 – unrealized gains of $6 million; 2023 – nil).

Derivatives in cash flow hedging relationships

The components of OCI (Note 25) related to the change in fair value of derivatives in cash flow hedging relationships before tax were as follows:

year ended December 31 (millions of Canadian $, pre-tax)	2025	2024	2023
Gains (losses) in fair value of derivative instruments recognized in OCI[1]			
Commodities	**7**	46	—
Foreign exchange	**(38)**	—	—
	(31)	46	—

1 No amounts have been excluded from the assessment of hedge effectiveness.

Effect of fair value and cash flow hedging relationships

The following table details amounts presented in the Consolidated statement of income in which the effects of fair value or cash flow hedging relationships were recorded:

year ended December 31 (millions of Canadian $)	2025	2024	2023
Fair Value Hedges			
Interest rate contracts[1]			
Hedged items	**(179)**	(126)	(98)
Derivatives designated as hedging instruments	**(30)**	(52)	(43)
Cash Flow Hedges			
Reclassification of gains (losses) on derivative instruments from AOCI to Net income (loss)[2,3]			
Commodities[4]	**19**	32	(85)
Foreign exchange[5]	**(50)**	—	—
Interest rate[1]	**(12)**	(12)	(12)

1 Presented within Interest expense in the Consolidated statement of income.
2 Refer to Note 25, Other comprehensive income (loss) and accumulated other comprehensive income (loss), for the components of OCI related to derivatives in cash flow hedging relationships.
3 There are no amounts recognized in earnings that were excluded from effectiveness testing.
4 Presented within Revenues (Power and Energy Solutions) in the Consolidated statement of income. In 2025, unrealized gains of $2 million were reclassified to Net Income (loss) from AOCI related to discontinued cash flow hedges (2024 - unrealized gains of $6 million; 2023 – nil).
5 Presented within Interest expense and Foreign exchange (gains) losses, net in the Consolidated statement of income.

Offsetting of derivative instruments

The Company enters into derivative contracts with the right to offset in the normal course of business as well as in the event of default. TC Energy has no master netting agreements; however, similar contracts are entered into containing rights to offset. The Company has elected to present the fair value of derivative instruments with the right to offset on a gross basis on the Consolidated balance sheet.

The following tables show the impact on the presentation of the fair value of derivative instrument assets and liabilities had the Company elected to present these contracts on a net basis:

at December 31, 2025 (millions of Canadian $)	Gross Derivative Instruments	Amounts Available for Offset[1]	Net Amounts
Derivative Instrument Assets			
Commodities	**508**	**(367)**	**141**
Foreign exchange	**66**	**(48)**	**18**
Interest rate	**25**	**(5)**	**20**
	599	**(420)**	**179**
Derivative Instrument Liabilities			
Commodities	**(404)**	**367**	**(37)**
Foreign exchange	**(83)**	**48**	**(35)**
Interest rate	**(42)**	**5**	**(37)**
	(529)	**420**	**(109)**

1 Amounts available for offset do not include cash collateral pledged or received.

at December 31, 2024 (millions of Canadian $)	Gross Derivative Instruments	Amounts Available for Offset[1]	Net Amounts
Derivative Instrument Assets			
Commodities	418	(290)	128
Foreign exchange	51	(49)	2
	469	(339)	130
Derivative Instrument Liabilities			
Commodities	(339)	290	(49)
Foreign exchange	(238)	49	(189)
Interest rate	(139)	—	(139)
	(716)	339	(377)

1 Amounts available for offset do not include cash collateral pledged or received.

With respect to the derivative instruments presented above, the Company provided cash collateral of $93 million and letters of credit of $73 million at December 31, 2025 (2024 – $133 million and $59 million, respectively) to its counterparties.
At December 31, 2025, the Company held less than $1 million in cash collateral and $102 million in letters of credit (2024 – less than $1 million and $75 million, respectively) from counterparties on asset exposures.

Credit-risk-related contingent features of derivative instruments

Derivative contracts entered into to manage market risk often contain financial assurance provisions that allow parties to the contracts to manage credit risk. These provisions may require collateral to be provided if a credit-risk-related contingent event occurs, such as a downgrade in the Company's credit rating to non-investment grade. The Company may also need to provide collateral if the fair value of its derivative financial instruments exceeds pre-defined exposure limits.

Based on contracts in place and market prices at December 31, 2025, the aggregate fair value of all derivative instruments with credit-risk-related contingent features that were in a net liability position was $5 million (2024 – net liability of $10 million), for which the Company has provided no collateral in the normal course of business. If the credit-risk-related contingent features in these agreements were triggered on December 31, 2025, the Company would have been required to provide collateral equal to the fair value of the related derivative instruments discussed above. Collateral may also need to be provided should the fair value of derivative instruments exceed pre-defined contractual exposure limit thresholds. The Company has sufficient liquidity in the form of cash and undrawn committed revolving credit facilities to meet these contingent obligations should they arise.

Fair Value Hierarchy

The Company's financial assets and liabilities recorded at fair value have been categorized into three categories based on a fair value hierarchy.

Levels	How Fair Value Has Been Determined
Level I	Quoted prices in active markets for identical assets and liabilities that the Company has the ability to access at the measurement date. An active market is a market in which frequency and volume of transactions provides pricing information on an ongoing basis.
Level II	This category includes interest rate and foreign exchange derivative assets and liabilities where fair value is determined using the income approach and commodity derivatives where fair value is determined using the market approach. Inputs include published exchange rates, interest rates, interest rate swap curves, yield curves and broker quotes from external data service providers.
Level III	This category includes long-dated commodity transactions in certain markets where liquidity is low. The Company uses the most observable inputs available or alternatively long-term broker quotes or negotiated commodity prices that have been contracted for under similar terms in determining an appropriate estimate of these transactions. Where appropriate, these long-dated prices are discounted to reflect the expected pricing from the applicable markets. There is uncertainty caused by using unobservable market data which may not accurately reflect possible future changes in fair value.

The fair value of the Company's derivative assets and liabilities measured on a recurring basis, including both current and non-current portions, were categorized as follows:

at December 31, 2025 (millions of Canadian $)	**Quoted Prices in Active Markets (Level I)**	**Significant Other Observable Inputs (Level II)**[1]	**Significant Unobservable Inputs (Level III)**[1]	**Total**
Derivative Instrument Assets				
Commodities	**154**	**279**	**75**	**508**
Foreign exchange	**—**	**66**	**—**	**66**
Interest rate	**—**	**25**	**—**	**25**
Derivative Instrument Liabilities				
Commodities	**(151)**	**(252)**	**(1)**	**(404)**
Foreign exchange	**—**	**(83)**	**—**	**(83)**
Interest rate	**—**	**(42)**	**—**	**(42)**
	3	**(7)**	**74**	**70**

1 There were no transfers from Level II to Level III for the year ended December 31, 2025.

The Company has entered into contracts, which commenced in 2025 and with terms ranging from 15 to 20 years, to sell 50 MW of power provided from specified renewable sources in the Province of Alberta. The fair value of these contracts is classified in Level III of the fair value hierarchy and is based on the assumption that the contract volumes will be sourced approximately 80 per cent from wind generation, 10 per cent from solar generation and 10 per cent from the market.

at December 31, 2024 (millions of Canadian $)	Quoted Prices in Active Markets (Level I)	Significant Other Observable Inputs (Level II)[1]	Significant Unobservable Inputs (Level III)[1]	Total
Derivative Instrument Assets				
Commodities	126	214	78	418
Foreign exchange	—	51	—	51
Derivative Instrument Liabilities				
Commodities	(116)	(217)	(6)	(339)
Foreign exchange	—	(238)	—	(238)
Interest rate	—	(139)	—	(139)
	10	(329)	72	(247)

1 There were no transfers from Level II to Level III for the year ended December 31, 2024.

The following table presents the net change in fair value of derivative assets and liabilities classified in Level III of the fair value hierarchy:

(millions of Canadian $, pre-tax)	2025	2024
Balance at beginning of year	**72**	(11)
Net gains (losses) included in Net income (loss)	**21**	54
Transfers to Level II	**(4)**	29
Purchases	**(1)**	—
Settlements	**(14)**	—
Balance at End of Year[1]	**74**	72

1 Revenues include unrealized gains of $21 million attributed to derivatives in the Level III category that were still held at December 31, 2025 (2024 – unrealized gains of $54 million).

28. CHANGES IN OPERATING WORKING CAPITAL

year ended December 31 (millions of Canadian $)	2025[1]	2024[1]	2023[1]
(Increase) decrease in Accounts receivable	**(332)**	(13)	(394)
(Increase) decrease in Inventories	**(55)**	(16)	(56)
(Increase) decrease in Other current assets	**(159)**	(97)	618
Increase (decrease) in Accounts payable and other	**13**	365	(206)
Increase (decrease) in Accrued interest	**30**	(40)	245
(Increase) Decrease in Operating Working Capital	**(503)**	199	207

1 Includes continuing and discontinued operations.

29. ACQUISITIONS AND DISPOSITIONS

U.S. Natural Gas Pipelines

Portland Natural Gas Transmission System (PNGTS)

In August 2024, the Company and its partner, Northern New England Investment Company, Inc., a subsidiary of Énergir L.P. (Énergir), completed the sale of PNGTS to a third party for a gross purchase price of approximately $1.6 billion (US$1.1 billion), including the third party's assumption of US$250 million of senior notes outstanding at PNGTS, split pro rata according to the PNGTS ownership interests (TC Energy – 61.7 per cent, Énergir – 38.3 per cent). The Company's share of the proceeds was $743 million (US$546 million), net of transaction costs. The pre-tax gain attributable to the Company of $572 million (US$408 million) was included in Net gain (loss) on sale of assets in the Consolidated statement of income, and the after-tax gain attributable to the Company was $456 million (US$323 million). The gain includes foreign currency translation gains of $15 million which were reclassified from AOCI to Net income (loss).

Columbia Gas and Columbia Gulf

In October 2023, TC Energy completed the sale of a 40 per cent non-controlling equity interest in Columbia Gas and Columbia Gulf to Global Infrastructure Partners (GIP) for proceeds of $5.3 billion (US$3.9 billion). The Company continues to have a controlling interest in these companies and will remain the operator of the pipelines. TC Energy and GIP will each fund their proportionate share of annual maintenance, modernization and sanctioned growth capital expenditures through internally generated cash flows, debt financing within the Columbia entities, or from proportionate contributions from TC Energy and GIP.

The sale was accounted for as an equity transaction of which $9.5 billion (US$6.9 billion) was recorded as non-controlling interests to reflect the 40 per cent change in the Company’s ownership interest in Columbia Gulf and Columbia Gas. The difference between the non-controlling ownership interest recognized and the consideration received was recorded as a reduction to Additional paid-in capital of $3.5 billion (US$3.0 billion), net of tax and transaction costs for the year ended December 31, 2023.

At December 31, 2024, as part of the contingent consideration included in the sale, TC Energy accrued a one-time special distribution to GIP of $33 million (US$23 million), or $24 million (US$17 million) net of tax, in Additional paid-in capital.

For the year ended December 31, 2025, the Company recorded $348 million as an out-of-period adjustment to reclassify a pro rata portion of its net investment hedge losses from AOCI to NCI related to the sale of 40 per cent of Columbia Gas and Columbia Gulf on October 4, 2023. Refer to Note 2, Accounting policies, for additional information.

Mexico Natural Gas Pipelines

Transportadora de Gas Natural de la Huasteca

In second quarter 2024, in accordance with the terms of the Company's strategic alliance, and in exchange for cash and non-cash consideration of $561 million (US$411 million), the CFE became a partner in TGNH with a 13.01 per cent equity interest. The transaction was accounted for as an equity transaction, of which $588 million was recognized in Non-controlling interests and $21 million was recognized as AOCI attributable to the CFE’s non-controlling interest. The difference between these amounts and the consideration received was recorded as a reduction to Additional paid-in capital of $27 million.

Power and Energy Solutions

Texas Wind Farms

In the first half of 2023, TC Energy acquired 100 per cent of the Class B Membership Interests in Fluvanna Wind Farm (Fluvanna) and Blue Cloud Wind Farm (Blue Cloud), respectively. Each of these operating assets has a tax equity investor which owns 100 per cent of the Class A Membership Interests, to which a percentage of earnings, tax attributes and cash flows are allocated. The tax equity investors' interests were recorded as non-controlling interests at their aggregate estimated fair value of $222 million (US$167 million).

TC Energy has determined that the use of the Hypothetical Liquidation at Book Value (HLBV) method of allocating earnings between the Company and the tax equity investors is appropriate as the earnings, tax attributes and cash flows from Fluvanna and Blue Cloud are allocated to its Class A and Class B Membership Interest owners on a basis other than ownership percentages.

Using the HLBV method, the Company's earnings from the projects are calculated based on how the projects would allocate and distribute cash if the net assets were sold at their carrying amounts on the reporting date under the provisions of the tax equity agreements.

TC Energy determined it has a controlling financial interest in both projects and has consolidated the acquired entities as voting interest entities. The tax equity investors' interests were recorded as non-controlling interests at their estimated fair values of $106 million (US$80 million) for Fluvanna and $116 million (US$87 million) for Blue Cloud. These transactions are accounted for as asset acquisitions and therefore did not result in the recognition of goodwill.

30. COMMITMENTS, CONTINGENCIES AND GUARANTEES

Commitments

TC Energy and its affiliates have long-term natural gas transportation and natural gas purchase arrangements as well as other purchase obligations, all of which are transacted at market prices and in the normal course of business. Purchases under these contracts in 2025 were $340 million (2024 – $347 million; 2023 – $335 million).

The Company has entered into PPAs with solar and wind-power generating facilities with terms extending to 2038 that require the purchase of generated energy and associated environmental attributes. At December 31, 2025, the total planned capacity secured under the PPAs is approximately 750 MW with the generation subject to operating availability and capacity factors. These PPAs do not meet the definition of a lease or derivative. Future payments and their timing cannot be reasonably estimated as they are dependent on when certain underlying facilities are placed into service and the amount of energy generated. Certain of these purchase commitments have offsetting sale PPAs for all or a portion of the related output from the facility.

Capital expenditure commitments include obligations related to the construction of growth projects and are based on the projects proceeding as planned. Changes to these projects, including cancellation, would reduce or possibly eliminate these commitments as a result of cost mitigation efforts. At December 31, 2025, TC Energy had approximately $0.8 billion of capital expenditure commitments, primarily consisting of $0.6 billion for its U.S. natural gas pipelines, primarily related to construction costs associated with ANR and other pipeline projects.

Contingencies

TC Energy is subject to laws and regulations governing environmental quality and pollution control. At December 31, 2025, the Company had accrued approximately $6 million (2024 – $8 million) related to operating facilities, which represents the present value of the estimated future amount it expects to spend to remediate the sites. However, additional liabilities may be incurred as assessments take place and remediation efforts continue.

TC Energy and its subsidiaries are subject to various legal proceedings, arbitrations and actions arising in the normal course of business. The Company assesses all legal matters on an ongoing basis, including those of its equity investments, to determine if they meet the requirements for disclosure or accrual of a contingent loss.

The following contingencies were concluded during the year ended December 31, 2025:

2016 Columbia Pipeline Acquisition Lawsuit

In 2018, former shareholders of Columbia Pipeline Group Inc. (CPG) commenced a class action lawsuit related to the acquisition of CPG by TC Energy in 2016. In 2023, the Delaware Chancery Court (the Court) found that the former CPG executives breached their fiduciary duties, that the former CPG Board breached its duty of care in overseeing the sale process and that TC Energy aided and abetted those breaches. TC Energy's allocated share of damages was an estimated US$350 million, plus post-judgment interest. TC Energy appealed the decision to the Delaware Supreme Court and on June 17, 2025, the Supreme Court issued its decision reversing the Court's finding of liability against TC Energy. On July 10, 2025, the Court granted the final order vacating its prior judgment and dismissing plaintiffs' claims against TC Energy. As a result, this matter is now concluded in TC Energy's favour with no liability. There is no further right of appeal.

Pacific Atlantic Pipeline Construction Ltd.

Coastal GasLink LP and Pacific Atlantic Pipeline Construction Ltd., one of the prime contractors on the Coastal GasLink pipeline, and their parent company Bonatti S.p.A, have reached a mutually acceptable resolution to their disputes. The settlement is not an admission of liability by either party and the parties have mutually released their respective claims in the arbitration. Details of the arbitration and the settlement are confidential, but it does include the retention by Coastal GasLink LP of the letter of credit funds drawn in 2024 and the settlement did not have a material impact on TC Energy's financial statements.

Macro Spiecapag Coastal GasLink Joint Venture

Coastal GasLink LP and Macro Spiecapag Coastal GasLink Joint Venture have reached a mutually acceptable resolution to their disputes. The settlement is not an admission of liability by either party and the parties have mutually released their respective claims in the arbitration. Details of the arbitration and the settlement are confidential and the settlement did not have a material impact on TC Energy's financial statements.

Guarantees

TC Energy and its partner on the Sur de Texas pipeline, IEnova, have jointly guaranteed the financial performance of the entity which owns the pipeline. Such agreements include a guarantee and a letter of credit which are primarily related to the delivery of natural gas.

TC Energy and its joint venture partner on Bruce Power, BPC Generation Infrastructure Trust, have each severally guaranteed certain contingent financial obligations of Bruce Power related to a lease agreement and contractor and supplier services.

The Company and its partners in certain other jointly-owned entities have either: i) jointly and severally; ii) jointly; or iii) severally guaranteed the financial performance of these entities. Such agreements include guarantees and letters of credit which are primarily related to delivery of natural gas. For certain of these entities, any payments made by TC Energy under these guarantees in excess of its ownership interest are to be reimbursed by its partners.

The carrying value of these guarantees has been recorded in Other long-term liabilities on the Consolidated balance sheet. Information regarding the Company's guarantees were as follows:

at December 31		2025		2024	
(millions of Canadian $)	Term	Potential Exposure[1]	Carrying Value	Potential Exposure[1]	Carrying Value
Bruce Power	Renewable to 2065	**88**	**—**	88	—
Sur de Texas	Renewable to 2053	**78**	**—**	93	—
Other jointly-owned entities	to 2032	**54**	**1**	59	1
		220	**1**	240	1

1 TC Energy's share of the potential estimated current or contingent exposure.

31. VARIABLE INTEREST ENTITIES

Consolidated VIEs

A significant portion of the Company's assets are held through VIEs in which the Company holds a 100 per cent voting interest, the VIE meets the definition of a business and the VIE's assets can be used for general corporate purposes. The consolidated VIEs whose assets cannot be used for purposes other than for the settlement of the VIE's obligations, or are not considered a business, were as follows:

at December 31 (millions of Canadian $)	2025	2024
ASSETS		
Current Assets		
Cash and cash equivalents	**167**	311
Accounts receivable	**989**	839
Inventories	**211**	205
Other current assets	**65**	121
	1,432	1,476
Plant, Property and Equipment	**49,445**	49,904
Equity Investments	**979**	865
Restricted Investments	**1,150**	950
Regulatory Assets	**109**	53
Goodwill	**456**	479
Other Long-Term Assets	**93**	59
	53,664	53,786
LIABILITIES		
Current Liabilities		
Notes payable	**535**	—
Accounts payable and other	**1,703**	1,866
Accrued interest	**216**	202
Current portion of long-term debt	**575**	2,062
	3,029	4,130
Regulatory Liabilities	**1,458**	1,232
Other Long-Term Liabilities	**51**	70
Deferred Income Tax Liabilities	**7**	7
Long-Term Debt	**13,904**	12,387
	18,449	17,826

Non-Consolidated VIEs

The carrying value of these VIEs and the maximum exposure to loss as a result of the Company's involvement with these VIEs were as follows:

at December 31 (millions of Canadian $)	2025	2024
Balance Sheet Exposure		
Equity Investments		
Bruce Power	**7,780**	7,043
Coastal GasLink	**896**	1,006
Other equity investments	**158**	160
Off-Balance Sheet Exposure[1]		
Bruce Power	**1,955**	1,877
Coastal GasLink[2]	**200**	265
Other equity investments	**—**	2
Maximum exposure to loss	**10,989**	10,353

1 Includes maximum potential exposure to guarantees and future funding commitments.

2 TC Energy is contractually obligated to fund the capital costs to complete the Coastal GasLink pipeline by funding the remaining equity requirements of Coastal GasLink LP through incremental capacity on the subordinated loan agreement with Coastal GasLink LP until final costs are determined. In December 2024, TC Energy made an equity contribution of $3,137 million to Coastal GasLink LP, which used the funds to repay the $3,147 million balance owing to TC Energy under the subordinated loan agreement. The repayment reduced the Company's funding commitment under the subordinated loan agreement to $228 million. In October 2025, TC Energy made an additional $65 million in equity contributions to Coastal GasLink LP, which reduced the Company's funding commitment under the subordinated loan agreement to $163 million. In addition to the subordinated loan agreement, TC Energy has entered into an equity contribution agreement to fund a maximum of $37 million for its proportionate share of the equity requirements related to the Cedar Link project.

SHAREHOLDER INFORMATION

TC Energy welcomes questions from shareholders and investors. Please contact:

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LISTING INFORMATION

Common shares (TSX, NYSE): TRP

Preferred shares (TSX):

Series 1: TRP.PR.A

Series 2: TRP.PR.F

Series 3: TRP.PR.B

Series 4: TRP.PR.H

Series 5: TRP.PR.C

Series 7: TRP.PR.D

Series 9: TRP.PR.E

Series 10: TRP.PR.L

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2025

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